High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid Forming Converters

Technical Report

ENTSO-E Technical Group on High Penetration of Power Electronic Interfaced Power Sources

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Executive Summary

Europe, in common with substantial parts of the world [1], [2], [3] is increasingly moving towards generating electricity from Renewable Energy Sources (RES) [4], which are predominantly connected to the power system via power electronic converters. In addition, power electronic interfaces are added on the demand side (smart loads, motor drive systems and electrical chargers for Electric Vehicles [EVs]) and also at the transmission level (e.g. bulk High Voltage Direct Current [HVDC] as well as offshore HVDC links) [5].

At times of high RES generation delivered at low marginal cost (due to no fuel cost), conventional thermal generation uses large Synchronous Generators (SGs) that are 'out of merit' and are therefore potentially disconnected. Periods in which RES have the potential to supply all, or close to all the system demand are increasing and becoming a reality for an increasing number of countries. Figure 2 represents a scenario for 2025 in this respect. Ireland is one extreme European example, where constraining/substituting wind above 65% of demand is already being experienced with installed wind capacity of 4 GW, and yet another 10 GW of new wind capacity is expected by 2030 [6]. Such a high uptake of RES is linked to dramatic reductions in installation costs of new wind and solar Photovoltaic (PV), making these sources increasingly competitive with thermal energy [1].

In parallel, the power systems in several European countries are undergoing structural changes, whereby business as usual is being challenged, most notably by larger and more volatile power flows over greater distances [4], [5], [7].

This report collates analysis since the end of 2016 by a group of experts from across the power industry called Technical Group High Penetration (TG HP), focused on the power electronic converters that are being used as an interface towards the Alternating Current (AC) power system in a wide range of applications covering power generation, transmission and consumption/demand, and which have the effect of changing the dynamic properties of the AC power system. The analysis is concentrated on one of the potential solutions for the extreme case of Power Electronic Interfaced Power Sources (PEIPS) contributing between 60 and 100% of the total instantaneous power supply. It defines the characteristics of one emerging solution, that of applying Grid Forming Converters (GFC). It does not address adequacy issues of low RES generation compared to demand. The TG HP has been reporting the developments via ENTSO-E to the Grid Connection European Stakeholder Committee (GC ESC), reflecting its initiation.

Extensive research on the topic of this report is being undertaken elsewhere, including the European R&D project MIGRATE which is currently releasing its reports [8], [9], [10], [11], [12], [13]. Several national and international organisations (worldwide) are engaged in current activity on this topic [6], [14], [15], [16], [17], [18], [19], [20], [21], [22] [23], [24], [25], [26], [27], [28], [29], [30]. This report concentrates on the potential contribution of GFC to the secure operation of the power system where its generation is dominated by PEIPS. The report does not claim to provide extensive cover of alternatives means to GFC to deliver the capabilities identified, although it does introduce the reader to one of them, the use of synchronous condensers, including the possible addition of flywheels.

Previous work developing Connection Network Codes (CNCs) has defined system needs and how to successfully satisfy such needs for lower PEIPS penetration, approximately up to 60% in a Synchronous Area (SA), as expressed in these CNCs at European level and at national level in Grid Codes or equivalent documents. However, in the operating range of PEIPS of 60 to 100% of the total demand at the time, fewer or no SGs (in the case of 100%) are connected based on economical 'in merit' energy market reasons.

The traditional electrical power system and electricity markets have been designed to work with SGs, and so these have traditionally provided various ‘inherent’ capabilities to the system critical to ensure the stable operation of the power systems during severe faults and even basic system survival during rare system splits. Due to the potential total absence of SGs approaches during periods of high penetration (HP) of PEIPS infeed, the wider industry has engaged in a closer examination of the lack of these system capabilities [4], [17], [31], [32]. Traditionally, the focus in the context of PEIPS has been on steady state and a limited number of dynamic (faster) aspects recently expanded to include PEIPS contributing fast fault current during system faults and extended contribution to frequency management (although this latter capability has been required from RES for more than 10 years in some countries). Demand side contributions in these contexts are emerging and have significant potential.

However, the analysis of situations of High Penetration of Power Electronics Power Sources (HPoPEIPS) [33] has identified further System Operator (SO) concerns, including the low or potentially inadequate supply of:

- Total System Inertia (TSI)
- Fault Current Infeed described as Fault Level (FL) and also affecting Short Circuit Ratio (SCR)

The combination of the above two elements is summarised by the term low system strength. The seven topics of concern in this context examined by TG HP are:

- Creating system voltage
- Contributing to fault level
- Sink for harmonics
- Sink for unbalance
- Contribution to inertia
- System survival to allow effective operation of Low Frequency Demand Disconnection (LFDD)
- Preventing adverse control interactions

These critical capabilities or behavioural characteristics must continue to be adequately delivered, even when operating close to a 100% penetration of converter interfaced power sources, in order to continue to ensure stable voltage, frequency and system angle under all operating conditions (steady state and disturbed).

Each of the above aspects could be treated in isolation, or alternatively solutions to these challenges could be sought in an integrated or holistic manner. In the view of some Transmission System Operators (TSOs), there is a risk associated with treating the challenges individually, as a positive contribution to one aspect may be detrimental to another. An example of this is that a pure form of contribution to synthetic inertia may be detrimental to control interactions by making these worse rather than better, and has therefore not been adopted (See [33] with associated further references). Although analysis of the power system characteristics and needs should be done in a holistic manner, some of the critical capabilities indicated above could be provided in a shared manner, e.g. while some converters create system voltage and contribute to fault level in the positive sequence, other converters in the power system could serve as sinks for unbalance. The value of a holistic approach versus shared delivery has not been fully analysed by this group.

To cover the above outline system needs, the TG HP classifies existing and future power park modules (PPMs) into Classes 1, 2 and 3, with Classes 1 and 2 reflecting respectively basic (early) and advanced (recent) capabilities of existing units. Section 2.1.3 defines the high level characteristics of a future Class 3 of PPMs and HVDC converter systems (HCS) [33] as follows:

‘Class 3 PPMs or HCSs shall be capable of supporting the operation of the ac power system (from EHV to LV) under normal, alerted, emergency, blackout and restoration states without having to rely on services from synchronous generators. This shall include the capabilities for stable operation for the extreme operating case of supplying the complete demand from 100% converter based power sources. The capabilities expected are limited by boundaries of defined capabilities (such as short term current carrying capacity and stored energy). Transient change to defensive converter control strategy is allowed (if it is not possible to defend the boundaries), but immediate return is required.’

Delivery of the complete package of the above services can be achieved through:

- Retaining (constraining on) a proportion of synchronous machines even when out of merit
    - SGs and or fitting Synchronous Condensers / Compensators (SCs)
- Equipping some of the future PEIPSs ready to contribute equivalent system characteristics

The control strategy containing this latter holistic range of PEIPS services (Class 3) has been described as GFCs. GFCs have the potential to deliver these capabilities inherently. This results from a combination of control laws which emulate voltage source behaviour within its limitations. An ENTSO-E document (published in 2017 with input from TG HP), IGD HPoPEIPS [33], contained a high level description of characteristics of GFCs, starting with the above Class 3 wording. This includes the ability to take the lead in creating the system voltage, rather than following a stable voltage delivered by SGs.

GFCs are in principle possible from across the converter interfaced equipment applications including converters associated with wind, PV, BESS (Battery Storage), HVDC links, or loads. Experience with GFC to date is limited, but rapidly expanding from a few MW, so far up to a 30 MW installation in South Australia [16]. So far, the most common adoption of GFC control is associated with BESS facilities mainly linked to PV installations [29], [30]. However, [28] demonstrates PV headroom for frequency services. Hence, GFC for PV without BESS may also be possible. For wind, the reported installations so far are limited to one 3 MW WTG on test [34], although this has recently been expanded to a trial over 8 weeks of a 23 turbine 69 MW wind farm equipped with GFC and inertia contribution tested successfully in the range of H of 0.2 to 8s [35]. This trial was implemented on an existing wind farm (commissioned in 2016), demonstrating that retrofit may not be entirely out of the question. It did demonstrate that a GFC performance evaluation is extremely challenging.

GFC has so far been established in applications (mainly in microgrids) where it is necessary to ensure a stable system operation already today, not yet driven by future proofing large systems approaching 100% PEIPS penetration. The R&D associated with GFC is rapidly expanding and widening in its coverage, with GFC/VSM proving to be the largest topic in the Oct 2019 Wind Integration Workshop in Dublin. However, GFCs have not yet been established by the major wind, PV and HVDC manufacturers in their mass market converter products, the nearest possibly being reported for wind [35] and for PV/BESS [30]. For wind and PV, the potential conflict with the maximising yield oriented operation has not yet been fully addressed. However, at the time of greatest need for GFC services (times of abundance of wind and sun and low demand), creating headroom (for PV see [28]) may have a modest market cost.

Adding GFC to demand (via mass market of consumer equipment such as EVs), although an option, is probably easier to achieve technically than gaining acceptance by users, considering the previous objections in the context of European CNCs to widescale autonomous contributions from cooling facilities (rejected largely on an emotional basis) and the current early signs of objections from some motor manufacturers to much simpler services such as Vehicle to Grid (V2G) [36].

Adding GFC capability to some or all the applications of converter interfaced equipment in the future will have cost implications. TG HP has not been able to fully analyse this (see section 2.4), due to a combination of incomplete specifications and commercial confidentiality. However, not proceeding with GFC capability has its own implications. SOs will certainly not simply accept the risk of operation without these capabilities with a lesser security of supply. Prior to developing the Network Codes, the European Commission established that security of supply should not be lowered. In the absence of GFC capabilities, SOs will have to rely on other capability providers, notably running thermal plant out of merit with cost and environmental impacts and/or the cost of providing SCs in the future, possibly with enhanced inertia using flywheels. Analysis published as early as 2013 which focused on one system in 2030 (GB) showed this cost to be prohibitive and likely to stop the further development of PEIPS at some point [31]. More recently in GB the cost to contain rate of change of frequency (RoCoF) due to inadequate inertia escalated to £150M last year (up from £60M previous year) [37]. An alternative evaluated in this paper was the addition of 10GVA SCs, although this would on its own (without adding flywheels) be unable to deal with the RoCoF aspect. In mainland Denmark, which unlike Ireland and GB is part of the large SA of Continental Europe (CE; via Germany), the approach to date has been to add SCs. On a worldwide basis, this is a common way of dealing with inadequate system strength, prior to GFC being available in the mass market.

At the same time (2013), representatives of the manufacturing industry called for an across-industry collaborative effort, focused on understanding the technical power system needs initially and secondly discussing market and costs efficiency, in order to address the potentially emerging new high penetration challenges [32]. A wide range of alternatives have subsequently been investigated and shared with stakeholders, with GFC emerging as one proposed long term contender that can allow operation at higher penetration levels.

One Cost Benefit Analysis process is reported to be in progress within the context of the GB Stability Pathfinder [14]. This process is expected to deliver from the market the necessary stability services for high penetration operation compliant with the performance specification [38]. The offered stability services are expected to be compared on a basis of cost per Effective MVA to the part of the system where the need has been identified. The urgency in GB relates to a commitment to have the GB networks ready by 2025 for stable operation without any fossil-fuel based generation (start of carbon free electricity operation). National Grid ESO has made stability the company’s number one priority for 2019/20 [37]. The GB Stability Pathfinder process [38] may shed more light on likely progress with inertia and system strength products via ancillary service market initiatives. It appears that Phase One [39] (delivery from 2020) is too early for GFC (and is therefore limited to proven synchronous solutions, e.g. SCs), whereas Phase Two [40] (delivery from 2023) allows some time for non-synchronous solutions (such as GFC) to qualify.

Ireland and Northern Ireland have introduced a Synchronous Inertial Response Service in addition to the more widespread used Fast Frequency Response (FFR) service [6]. EirGrid’s commitment to these and expected future additional services is reflected in the rapid acceleration of spend on ancillary services, expected to reach 30% of total electricity costs by 2030 having come from approximately 5% a few years ago [41]. The MIGRATE study for Ireland [10] indicates that EirGrid will need GFC type performance to retain stability for operation beyond 70% penetration. In October 2019, EirGrid reported that it is at the starting point of a process to establish its strategy to move its penetration capability from 70 to 95%, which is deemed necessary to allow a three-fold increase in wind capacity and some level of PV [6].

In addition to the choices of constraining SGs and equipping PEIPS to provide the capabilities, for the GFC open questions remain (elaborated in section 4):

- What proportion of the converter interfaced equipment needs to have the seven characteristics in question?
- Where and when will the capabilities need to be available?
- Are some types of converter interfaced equipment better suited to deliver GFC, with characteristics that are cheaper and more effective than others, e.g. small embedded units versus larger units connected at higher voltages?

A possible transitioning to GFC involves the following challenges for the industry [42] which operates in increasingly competitive markets:

- Delivering new capabilities requires R&D resources and hence incurs expenditure.
- Introducing GFC is a major change. Ensuring that the desirable characteristics embedded in existing designs and developed over decades are not lost is essential.
- Power plants incorporating the new GFC functionalities may have additional life-cycle costs (currently unknown) to provide increased capabilities.
- On a commercial basis, in the view of the wind industry the new type of technology would need at least 5 years to be developed from the moment manufacturers have a clear specification.
- Added capital cost in mass manufacture is likely, mainly focused on energy storage and increased converter rating.
- The topic of cost has some coverage, although limited, in this report; see section 2.4.
- Offering GFC as well as existing products adds complexity and cost.

Manufacturers need commercial incentives to proceed with GFCs, implying a willingness on the part of developers to pay a premium for the new capabilities [42], [43]. Regardless of choice of incentives, it is important to establish a level playing field between different technologies. Currently, such incentives do not exist widely (except in some microgrid contexts). They could arise from:

- Mandatory requirements, such as those in grid codes.
- Opportunities for additional revenue streams, e.g. ancillary services markets, priority in unit commitment and curtailment processes.
- Negative incentives for non-compliant equipment, e.g. uncompensated constraining off.

If for some or all of the seven challenges identified above a market-driven approach is adopted, questions arise as to the market design. Would available capability or utilisation be remunerated? Would payments have to be location-based? Could the entire required range of services be obtained on the market? In this report, seven different partially interacting capabilities have been identified, providing technical background to this subject. In the context of inertia, early adopters (such as Ireland and AEMO in Australia) have started with synchronous plant (SGs and SCs) to deliver a minimum TSI [6]. GB is following this for Phase One of its Stability Pathfinder for delivery from 2020 [39], whereas its Phase Two with delivery from 2023, [40] will allow some time to prove the capabilities of GFC type offerings.

Compared to existing AS markets, services to deal with potential low system strength and inertia (all the seven challenges) appear more complicated, especially across a SA such as CE. The equivalent services are currently not widely defined regarding the technical performance (exceptions include AEMO and GB), nor are they subject to payment to existing SGs, other than through the earnings for constraining on / must run arrangements.

From the analysis based on ENTSO-E's 2018 TYNDP [44] (see section 1.1), it is the view of TSOs that time is limited in terms of starting to provide the optimal solutions (lowest cost and environmentally sound) for coping with the high penetration of PEIPSs for an increasing number of European countries, even extending to part of the large system of CE. The urgency is greatest in the smaller SAs such as GB and Ireland/Northern Ireland [10], followed by countries in the larger SA of CE which are already operating at times in the 60-100% penetration range for PEIPSs.

Abbreviations

AC: Alternating current

AS: Ancillary services

BESS: Battery energy storage systems

CE: Continental Europe

CNCs: Connection network codes

DC: Direct current

DLL: Dynamic Linked Library (used in numerical simulations)

EMT: Electromagnetic transient

EVs: Electric vehicles

FFCI: Fast fault current injection

FL: Fault level

FRT: Fault Ride Through

GB: Great Britain

GC ESC: Grid Connection European Stakeholder Committee

GFC: Grid forming converter

HIL: Hardware in the loop

HP: High penetration

HPoPEIPS: High penetration of power electronics power sources

HVAC: High voltage alternating current

HVDC: High voltage direct current

LCC: Line-commutated converter

HCS: HVDC Converter System

LFDD: Low frequency demand disconnection

LOM: Loss of main

LFSM-O: Limited frequency sensitive mode of over-frequency

LFSM-U: Limited frequency sensitive mode of under-frequency

MMC: Modular multi-level converter

MPP Tracking: Maximum Power Point tracking

NPS: Negative phase sequence

PEIPS: Power electronic interfaced power sources

PLL: Phase-locked loop

PPM: Power park module

PPS: Positive phase sequence

PT1: First order lag

PV: Photovoltaic

PWM: Pulse width modulation

RES: Renewable energy sources

RoCoF: Rate of change of frequency

SA: Synchronous area

SCs: Synchronous condensers/compensators

SG: Synchronous generator

SCR: Short-circuit power ratio

SI: Synthetic inertia

SIL: Software in the loop

SO: System operator

SSCI: Sub/super-synchronous controller interaction, sub/super-synchronous controller instability

SSI: Super-synchronous instability

SSR: Sub-synchronous resonance

TG HP: Technical Group High Penetration

TSOs: Transmission System Operators

TYNDP: Ten-Year Network Development Plan

TSI: Total system inertia

V2G: Vehicle to grid

VSC: Voltage source converter, voltage-sourced converter

VSM: Virtual synchronous machine

1 The Interconnected European Power System: Power System Stability Challenges with High levels of Power Electronic Based Sources

1.1 Moving towards high penetration of power electronic interfaced generation

The European system is anticipated to accommodate a steadily increasing share of RES. Figure 1 presents the main network development scenarios as presented in the Ten-Year Network Development Plan (TYNDP) report of ENTSOE (version 2018) [44]. In these scenarios, the large penetration of RES (mainly wind and solar) can be clearly observed, here defined as shares of energy. Figure 2 illustrates the highest instantaneous percentage of RES (including small hydro) penetration in relation to demand (power and not energy) occurring in any hour of the year in European countries in 2025, from studies associated with TYNDP 2016 [7]. From these figures, eight countries in total will reach up to the level of 100% of instantaneous demand available from renewable generation and 22 countries will reach at least 50% for the most challenging hour.

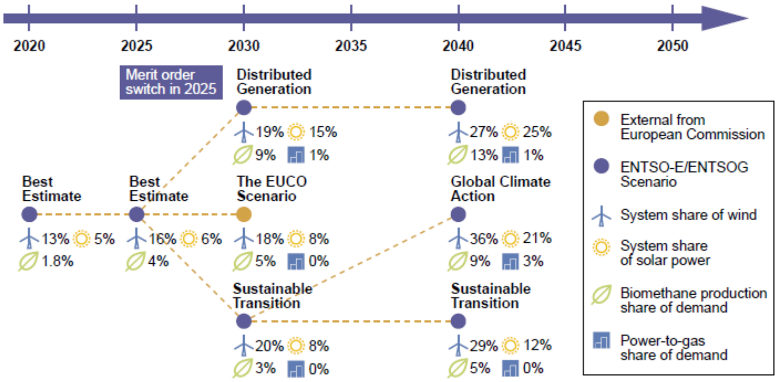

Figure 1. Scenarios which comply with the energy policy targets.

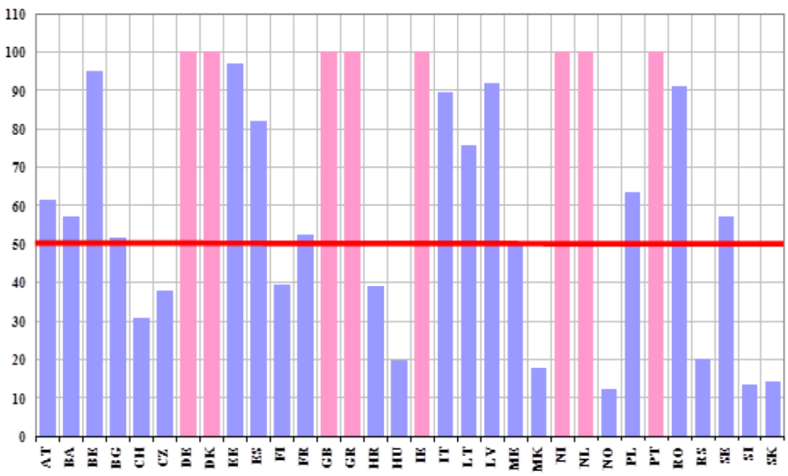

Figure 2 . Expected highest hourly penetration levels of RES in Europe by 2025 (2016 forecast) in % of demand.

The state-of-the-art renewable generation technologies (especially wind and solar) are interfaced with the networks through power converters (DC-AC or AC-DC-AC). Hence, the massive penetration of power converters throughout the distribution and transmission system changes the overall power system dynamic profiles. This is primarily caused by the displacement of the synchronous generation fleet, and secondarily by the fast time constants introduced by power electronic converters and actuators.

In addition, the system is moving from the classical centralised power system where large synchronous generation units ensure power system stability and robustness, towards a decentralised power system where the generation shifts into the distribution level. The latter introduces a twofold challenge. First, the observability of the generation fleet in the medium and low voltage networks becomes challenging for SOs. Second, the load flow patterns become volatile among transmission and distribution networks, resulting in increased reverse flows and faster voltage variations through the system nodes. In addition, the RES variability increases the need for larger and more variable power transits across the transmission corridors. This is achieved in part through pushing the existing system harder and in part through new transmission capacity, although extensive difficulties exist in delivering these in the timescales required. On the demand and transmission side, similar trends are being observed with the load being increasingly interfaced with power converters, e.g. industrial motors or EVs, while much greater HVDC transmission capacity is expected by 2030. Overall, these changes increase the interdependency between TSOs, to ensure overall system security of supply.

1.2 Power system stability challenges

A recent report from the sub-group System Protection and Dynamics (SG SPD) of ENTSO-E has ranked the increase of RoCoF due to the high penetration of power converter interfaced generation as a top power system stability challenge for the CE system [45]. The EU-Horizon-2020 funded project MIGRATE [8] conducted a survey among 21 European TSOs aimed at identifying power system stability challenges as perceived by the industry under high penetration of PEIPSs. An analysis of the eleven identified power system stability challenges/issues is presented in figure 3 [9].

Ranking	Score	Issue
1	17.35	Decrease of inertia
2	10.16	Resonances due to cables and Power electronics
3	9.84	Reduction of transient stability margins
4	8.91	Missing or wrong participation of PE-connected generators and loads in frequency containment
5	8.19	PE Controller interaction with each other and passive AC components
6	7.50	Loss of devices in the context of fault-ride-through capability
7	7.00	Lack of reactive power
8	6.91	Introduction of new power oscillations and/or reduced damping of existing power oscillations
9	6.09	Excess of reactive power
10	4.27	Voltage Dip-Induced Frequency Dip
11	3.87	Altered static and dynamic voltage dependence of loads

Figure 3. Ranking of the power system stability issues as identified by European TSOs in the context of the MIGRATE Project [9]. (Theoretical maximum score: 27; theoretical minimum score: 0).

1.2.1 The reduction of total system inertia

TSI is a metric which identifies, and to a certain degree, quantifies the fundamental frequency robustness of an interconnected power system [9], [46], [47], [48]. A direct metric that reflects the levels of TSI is the RoCoF (in Hz/s) in the frequency containment period. Figure 4 provides a qualitative overview of a typical frequency response following generation outage, indicating the effect of TSI on the initial RoCoF. The response of the whole system depends on the slower responses of Frequency Sensitive Mode control (governor time constants), the faster responses of generation in limited over- and under-frequency sensitive mode control (LFSM-O and LFSM-U) if certain frequency limits are violated, the load sensitivity to the frequency and the frequency containment reserves.

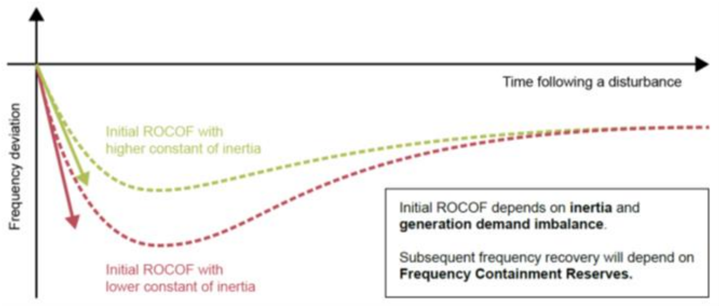

Figure 4. Qualitative demonstration of the effect of TSI constant on the expected frequency response of interconnected system in the frequency containment period (Source: ENTSO-E - TYNDP 2018) [4].

For the normal interconnected operation of the European power system, the inertia is sufficient considering the normative loss of 3000 MW in the CE power system [47]. The most critical situations will be the case of system split during high power exchange conditions [45] (see discussion below).

Other synchronous zones have already started to experience frequency stability challenges. For example, in GB an incident of loss of generation associated with a high RoCoF in 2012 (incident initially caused by a large infeed loss) lead subsequently to SO action at times of high penetration, to take costly market intervention to substitute low inertia power sources (generally RES) by high inertia power sources (often thermal SGs) to avoid an excessive RoCoF through ensuring a minimum level of TSI [25]. Analysis published in 2013 [31] indicated that continuing to rely long term on this strategy would be precipitously expensive (costing billions by 2030). The report from National Grid ESO [37] shows that this cost is rapidly increasing, having reached £150M last year up from £60m the previous year, dominated by the management of the maximum allowed RoCoF. For the Nordic synchronous area, in [49] it is stated that kinetic energy in the Nordic system is ‘expected to reach lower levels than today and what we have historically seen’ due to an increase in wind and small hydro plants. For the Baltic SA, a key future change is the planned disconnection from the Russian synchronous system to be replaced by connection to CE.

Figure 5 below illustrates the TSOs’ view that a national per unit TSI constant H sometimes falling below 2 s (compared with a traditional value of about 5–6 s) is a cause for concern. Report [5], which encloses the vision of European TSOs on the 2030 power system, recognises such challenges. At least two SAs, GB and Ireland, and a number of individual countries’ contribution within CE are expected to fall within this category, highlighting their need to prepare their strategy and possibly also start taking action (see countries in red). The IGD HPoPEIPS [33] gives further step-by-step guidance in a process diagram on its page 12. This concludes in step 3, where relevant ‘Work out detailed requirements including parameters for the implementation and associated models to study the effectiveness as well as compliance tests. Introduce new requirements at national level’.

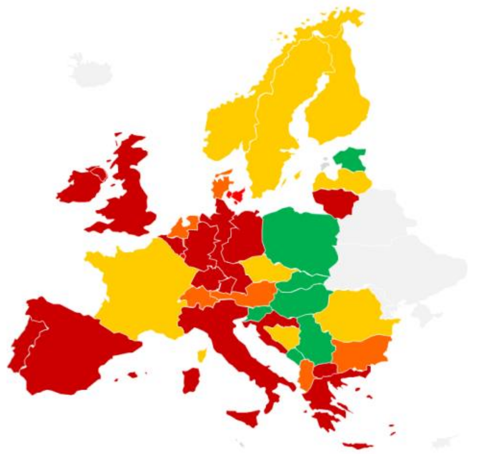

Figure 5. Indicating contribution of each TSO to the TSI constant (source: TYNDP 2016 reflecting 2030 scenario, [7]).

Figure 6, covering a 2030 scenario from TYNDP 2016 [7], presents an example of the indicative distribution of the TSI contribution for each country at the most sensitive time for the overall SA (time of lowest TSI). A process is defined in the IGD PEIPS [33] suggesting further analysis is required when the TSI contribution is predicted to be extremely low (H<2s suggested), to initiate discussion with adjacent countries and to give consideration of the possible need to develop remedies.

With the aim of further quantifying the effect of a large share of PEIPS on the TSI, figures 6 and 7 present the evolution of the inertia constant in two (out of five) of the European SAs for three different scenarios for each of 2030 and 2040, assuming no contribution from PEIPS. It can be observed that there is a progressive decrease in the inertia constant of the CE system (figure 6) when moving towards 2040. The decrease of system inertia is greater and earlier in the smaller SAs such as GB (Figure 7), with the inertia constant reaching extremely low values, with H even below 1 s for about 20% of the year, compared to a former norm of H of approximately 5–6 s.

The reduction in total system inertia significantly affects the capability to provide instantly matching balancing power e.g. for loss of a large infeed [50]. Frequency response time constants would then have to be lower than traditional, in order to provide enough power fast enough to the system, e.g. for the less extreme penetration challenge introducing FFR may be adequate. The decrease in the TSI increases the RoCoF. In the smaller SAs with high penetration (GB [51]& Ireland [41]) with the loss of the largest infeed (generation or HVDC link), RoCoF values are reached above the grid code thresholds set in the network codes for generators to remain connected, creating further frequency stability concerns. In the GB system, low TSI and high ROCOF are conditions that threaten in future (when close to 100% penetration) to reduce the effectiveness of the LFDD. In GB, extreme RoCoF sensitivity of the smallest embedded plant (<5 MW) equipped with Loss of Main (LOM) protection based on RoCoF with settings of 0.125 Hz/s as well plant with vector shift LOM protection can add to largest infeed loss. For the 9 August 2019 partial black-out event [52], when stage 1 LFDD operated at 48.8 Hz, a loss of 500 MW from LOM protection 'mal-operation' contributed significantly to the event. Although this is not the overall case for CE, in some contingencies (system split), such high RoCoF values may occur even in parts of CE [53].

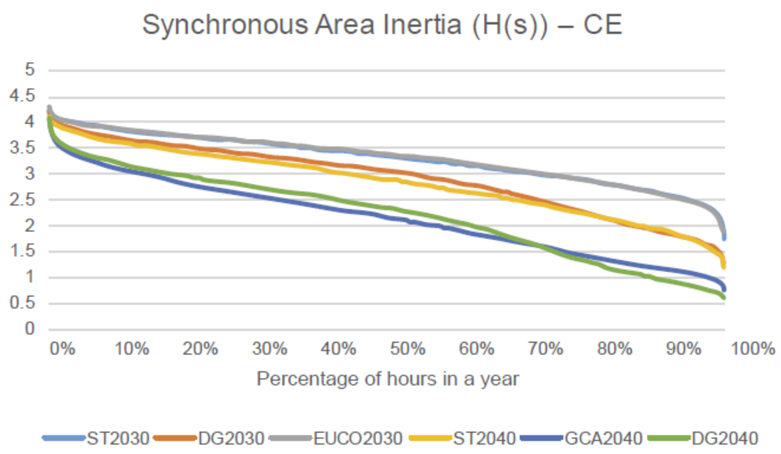

Figure 6. Inertia constant in the CE system for given percentage of hours per year under various grid development scenarios, [44].

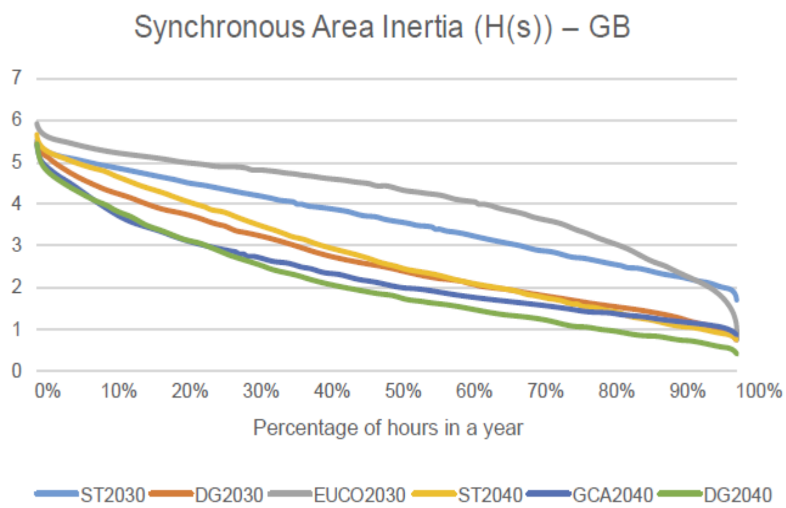

Figure 7. Inertia constant in the GB system for given percentage of hours per year under various grid development scenarios, [44].

1.2.2 System split

For the case of the CE power system, rare events such as system splits (currently experienced once in decades), becomes critical under high penetration levels of renewable generation sources. System split is identified as a grid extreme contingency leading to separation of the system into asynchronous zones. Exports and imports before the system split event become power imbalances for the separate islands after the split. A system split is more likely to occur across highly loaded weak transmission corridors. Developments of the European Electricity Markets are leading to the transit flows gradually increasing in magnitude, and they are more volatile. The potential imbalance after a rare system split which the systems need to survive is expected also to increase, bringing the system to its physical limits in terms of balancing capability.

A system split event could lead to a situation which is outside the pre-defined limits for frequency containment reserves (3 GW in CE). The most common remedial actions are LFDD, LFSM-U and LFSM-O. It is uncertain and hard to predict when and under what conditions a system split case will occur and what parts of the system will be split. Within ENTSO-E (System Protection & Dynamics), a methodology has been developed for the analysis of system splits [54]. The analysis has also been validated by comparison of recordings of real past events, including the 3-way split in 2006 shown in figure 8, in which the capabilities provided by the running SGs contributed greatly to system stability and the avoidance of system collapses. Further work on long-term frequency stability scenarios with less synchronous generation in operation are in progress and expected to give rise to relevant requirements [53]. The expected values of unbalance for future system development are expected to be 40% with a RoCof of more than 2 Hz/s [9], [55]. The latter, in conjunction with the expected reduction in TSI, presents risks to the overall system security. LFDD can be ineffective when inertia is low and power deficit is high (as may be the case with a system split) because the ROCOF can be so high that LFDD is not fast enough to halt frequency drop. As an example, in Australia, AEMO has determined that ROCOF must be less than 3 H/s to allow LFDD to operate effectively and inertia should be maintained to ensure this for all secured events (i.e. excluding system splits). It is worth noting that the RoCof observed during the Australian black-out event was 6 Hz/sec [56].

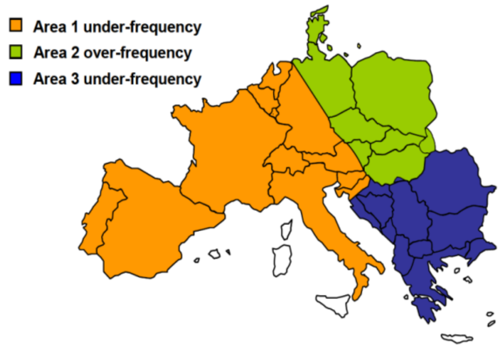

Figure 8. The system split event that occurred in the CE system in 2006.

1.2.3 Short-circuit power levels

Already today in many countries and regions, different levels of short circuit power levels are observed / reported, mainly between central areas and areas at the system edges. This difference will increase in the future, raising both stability but also political questions. References [51], [57] from National Grid SO reflect and quantify the expected reduction in the short circuit power levels in the transmission system. In general, the short circuit power levels trends are regional, different across different SAs and operating conditions.

The overall consequence of low system strength is varied and complex across all categories of system stability (rotor angle, voltage and control interactions). The direct effect of the reduction in the short circuit power levels in the network is reflected in the deeper (in the medium and low voltage network) and widespread (in geographic area) voltage dips in the event of severe transmission network faults. The latter would affect the short term voltage stability and moreover, the rotor angle stability of remaining conventional synchronous generation units (reducing the critical clearing times). Several TSOs [9] have reported loss of devices in the context of fault-ride through capability. These TSOs have mentioned as the main reason the reduction of the short circuit power levels and the propagation of voltage dips which resulted in trips from under-voltage protection. Clearly, outages of such nature would affect the frequency stability and would have a more global system effect under high penetration of PEIPS.

With regard to PEIPS, it is well known that their stable and robust operation is affected significantly by the correct operation of the phase-locked loop (PLL) modules. In weak grid connection environment, the stable and robust operation of the PLL along with the application of vector current control loops (grid following) could be a potential reason for PEIPS instability.

1.2.4 Rotor angle stability

Rotor angle stability refers to the ability of the SGs connected to system to remain in synchronism when subjected to grid disturbances. With regard to the rotor angle stability, both small and large signal, the following two concerns are identified in [9]:

- Introduction of new power oscillations and/or reduced damping of existing ones.
- Reduction of transient stability margins.

1.2.5 Voltage stability

Voltage stability is associated with the capability of a power system to maintain stable voltage magnitudes during both normal and disturbed conditions. Key to voltage stability are the system loads and the dynamic behaviour of sources during disturbed conditions, in terms of active and reactive power injections. Voltage instability occurs in the form of progressive voltage rise or fall, known as voltage collapse. SOs are responsible for controlling voltage, so that it remains between specific limits, both in steady and transient states, and could rely on the assistance of the producers connected to its grid to do so. Injection or absorption of reactive power at each node induces voltage differences between nodes which become more significant under high penetration of PEIPSs. Thus, with regard to voltage stability, concerns as identified by TSOs in [9] are summarised as:

- Loss of generation in the context of fault-ride through capability
- Voltage dip-induced frequency dip
- Lack of reactive power sources
- Excess of reactive power sources
- Altered static and dynamic voltage dependence of loads
- Inadequate support to restore system voltage immediately post fault

Analysis of the extreme case of 100% PEIPS penetration [18] demonstrates that a response is required in the first quarter cycle (within 5 ms) to avoid system collapse. Moreover, studies presented in [12], [10], [58] have shown that the disconnection of conventional units has resulted in significant control interactions and unstable operation of wind power plants in cases with high PEIPSs (both in normal and fault conditions).

1.2.6 Other instabilities relating to fast dynamics of power converters

Further concerns include low synchronising torque (power) between generation sources, to overcome sudden voltage angle disturbances (at the fundamental frequency). The issue of Sub Synchronous Resonance in context of interactions with conventional machines is likely to become more complex as operating conditions become more variable.

- The adverse control interactions between converter controllers (connected electrically close) is becoming a more significant issue. Such interactions may become visible as Sub Synchronous Resonances (SSR) or Super Synchronous Instability (SSI also called Harmonic Instability). As PEIPS becomes dominant, these interactions may no longer remain local [31], [59].
- In the absence of SGs, the system may lack 'sinks' to correct low order system harmonics including inter-harmonics as well as lacking 'sinks' to correct phase unbalance.

2 Power System Needs under High Penetration of PEIPSs: The need for Grid Forming Converters

2.1 Classes of Power Electronic Interfaced Power Sources arising from IGD HPoPEIPS

The previously issued IGD HPoPEIPS [33] introduced 3 levels of capabilities of PEIPSs using the terms Classes 1, 2 and 3, with Class 1 as the highest capability and Class 3 as the lowest. Following further consideration, to ensure greater clarity regarding the progression in requirement, the order presented here has been reversed, with Class 1 being the basic level, Class 2 reflecting advanced control (typical reflecting recent code requirements) and Class 3 defining the capability needs expected in the future context of high penetration of PEIPS. Class 2 is further subdivided into A (lowest), B and C (highest). These classes cover renewable energy defined in Network Connection Codes as PPMS as well as HCSs. A brief high level description for these classes is given below. Class 3 includes the capabilities of Class 2 and Class 2 in turn, encompasses the capabilities of Class 1. For full details of existing requirements the CNCs [60], should be consulted along with their implementation in each country in national documents [61].

2.1.1 Class 1 Power Park Modules

Class 1 PPMs represent the basic level of grid-connected converter functionality, with a main focus on basic converter survivability, reflecting requirements for the smallest (Type A) PPMs. HCSs with only Class 1 capabilities are not covered in CNCs.

Listing of system needs / with respect to PPM capabilities

Basics PPM – with focus on survival

- Full frequency operating range
- Full voltage operating range
- Basic reactive controls – e.g. Unity Power Factor
- LFSM-O
- Complies with local power quality requirements (e.g. harmonics / unbalance current)

2.1.2 Class 2 PPM / HCS

A Class 2 PPM / HCS has ‘Advanced Control’ and additional capabilities over and above a Class 1 PPM. It is possibly subdivided into 2A, 2B and 2C (2C highest). The listing of system needs with respect to PPM/HCS capabilities, reflecting CNCs’ [60]progressive requirements for gradually larger PPMs (Types B, C and D) as well as some non-mandatory capabilities (2C), is as follows:

- Fault Ride-Trough 2A
- Voltage control – steady state 2A
- Voltage control – dynamics 2B
- Voltage control – at P=0 2C
- FSM 2B
- LFSM-U 2B
- Provides damping 2C
- Fast Fault Current Injection (FFCI; see IGD) 2C

- FFCI – Periods B + C for Positive Phase Sequence and Negative Phase Sequence (PPS & NPS)
- FFCI – Periods B + C provide bias choice between reactive & real current

2.1.3 Class 3 PPM / HCS

Class 3 PPMs or HCSs shall, in addition to capabilities of Class 2C, be capable of supporting the operation of the ac power system (from EHV to LV) under normal, disturbed and emergency states without having to rely on services from SGs. This shall include the capabilities for stable operation for the extreme operating case of supplying the complete demand from 100% converter based power sources. The support services expected are limited by boundaries of defined capabilities (such as short term current carrying capacity and stored energy). Transient change to defensive converter control strategy is allowed (if it is not possible to defend the boundaries), but immediate return is required.

In addition to capabilities of PPMs or HCSs of Classes 1 and 2, Class 3 may in future provide PPM or HCSs controls with single cycle support services allowing 100% power electronic penetration, including in headline terms (further info follows later):

- Creates system voltage (does not rely on being provided with firm clean voltage)
- Contributes to Fault Level (PPS & NPS within first cycle)
- Contributes to TSI (limited by energy storage capacity)
- Supports system survival to allow effective operation of LFDD for rare system splits.
- Controls act to prevent adverse control system interactions
- Acts as a sink to counter harmonics & inter-harmonics in system voltage
- Acts as a sink to counter unbalance in system voltage

A description of one practical implementation is as follows: The control strategy of grid forming PPMs or HCSs provides an inherent performance resulting from presenting to the system at the connection point a voltage behind an impedance, in effect a true voltage source.

There could in future be differentiation between controllable contributions from GFC (further freedoms of design) and inherent contributions from SG to these 7 capabilities.

2.2 Requirements for Grid Forming Power Electronic Interfaced Power Sources

For grid forming capability of Class 3, the requirements are listed above in 2.1.3. They are described individually in the following sub-sections 2.2.1 to 2.2.7 with respect to performance aspects in order to support up to 100% PEIPS penetration and are relatively high level descriptions of desired performance.

Other aspects are collated thereafter across the requirements covering:

- 2.3 Operational boundaries for GFC performance
- 2.4 Cost considerations
- 2.5 Must run units
- 2.6 SCs
- 2.7 Spatial distribution of Grid Forming Units or must run units
- 3 Proposed tests and benchmarking

2.2.1 Create system voltage

To provide instant power to suddenly changing loads in an electrical power system, there is a need for PPMs and HCSs with a voltage source characteristic. In this section, the most important characteristic requirements for components providing this capability are outlined.

General Characteristics and fundamental capabilities

The PPM or HSC provides a three-phase voltage. In the first case, within the capability of the source (especially in terms of current and power limits), the voltage is maintained in amplitude, frequency and phase angle independently from a load connected to the source. In the latter case, the resulting load flow depends on loads and current sources in the system only. The basics of various options of GFC controls are explored as presented in [10], [18], [58]. An early national draft Grid Code requirement (not mandatory, but paid for capability) is given in [38] calling for 'capable of operating as a voltage source behind a reactance over a frequency band of 5Hz to 1kHz before, during and after a fault'.

Since in large interconnected power systems this capability for the system cannot be covered by a single PPM or HSC, there is a need for the PPM or HCS to be capable of running in parallel with other AC voltage sources. To provide a high robustness and modularity, inherent mechanisms shall be implemented that lead to stable operating points without the need of control setpoints given by an external entity for the means of parallel operation (e.g. f(P)-droop).

The resulting amplitude and frequency of the voltage at the terminals of the PPM or HSC may depend on load, capability, internal control and optional external control setpoints in order to ensure stable operating points of the power system. Single Phase PPMS may in future contribute to system dynamic damping (increase of SCR and Inertia), but will usually not provide voltage source capabilities (voltage and frequency). An operation as voltage source would require additional hardware (supervisory control, protection handling) and safety procedures not adequate for small installations.

Further important, more detailed and optional characteristics and quality criteria:

- Independency
  - The PPMs or HCSs capability of providing a system voltage does not depend on the existence of an external AC voltage source.
- Dynamic Capability
  - Ride through and maintain synchronism during transient events such as grid faults and load steps in the system
  - Capability to supply linear and nonlinear loads of active and reactive power with a supply voltage of commonly accepted quality (specify e.g. THD_U at given THD_I) stationary
  - Transient active and reactive power need / demand resulting from load steps can be fulfilled
  - The capability to limit and control the rate of change of voltage angle in transient conditions in order to ensure overall system stability. In GB the 'Stability Pathfinder' [39] section ECC6.1.19.3(xvi) of the draft Grid Code specifies the withstand capability of large voltage angle changes of 200 degrees lasting no longer than 5 ms and 90 degrees lasting no longer than 60 ms.

2.2.2 Contribute to fault level / fault current contribution

The overall objective of an adequate fault current contribution consists in limiting the impact of a grid fault (e.g. short circuit on transmission level) on generators and consumers in the wider area of the fault, and as such avoids the risk of immediate voltage collapse. In addition, the functionality of protection equipment in the grid has to be ensured [62], [63], [64], [65] .

The grid forming converter should provide an injection of current, which in case of low impedance faults is limited to the converters' overcurrent capacity. The desired behaviour during fault depends on fault location, fault type and time interval of fundamental period, see [33]. In [18] emphasis is attached to speed of delivery, suggesting that for 100% penetration, delivery within the first quarter of a cycle (5 ms) is essential.

Protection system in the high voltage grid requires sufficient amplitude of fault current in the first 20-30 ms after the fault. The aim of fault level contribution from PEIPS (PE connected equipment) is to ensure the minimum voltage drop seen by other assets (especially more distant from the fault) to prevent tripping due to under-voltage protection and to help keep the power system stable (if in a 100% penetration scenario no sources contributed to fault level, then a fault could trigger shut – down, unstable voltage recovery or unsafe operation of the system). Existing protection schemes should be revised once requirements to GFC for high penetration of PEIPS have matured and settled. Challenges for existing protection systems in high penetration of PEIPS, particularly distance protections, are discussed in [62], [63], [64], [66].

The voltage source characteristics of a GFC means that it would contribute to the system strength of the power system. The contribution to the system strength of a GFC can be assessed by the characteristic small signal short circuit impedance and by the maximum current contribution by the GFC, for definitions see [33].

Current control / clipping

The grid forming converter control, regardless of the technology implementation, behaves as a Thevenin source and impedance. The voltage source is controlled in frequency and in amplitude, and the impedance can be emulated, a real impedance or a combination. As such, the GFC contributes to system strength. Regardless of the technology implementation, the GFC must have a behaviour like a Thevenin source and impedance and, at the same time, the GFC must be able to protect itself by limiting the current according to the converter overcurrent capacity. By this, the GFC will respond to a voltage change with a large fast current as a voltage source behind an impedance, whereby exceeding the extreme current and power limits is prohibited by modifying the voltage angle or magnitude.

If current limitation is necessary during voltage drops and phase (voltage angle) shifts/changes in the network, two options will be available: a) switch over to current control during the fault period in order to limit the current to below the rated current capacity of the converter, b) implement some current clipping features (done either by HW or SW depending on converter technology), for examples of the latter with SW. It is, at the present time, an unresolved problem for the power industry to investigate how the current should be prioritised once the GFC hits its current limit during a fault, i.e. should the current be proportionally scaled or should active or reactive power be prioritised?

Comparison with existing network codes

The existing national implementations of European wide CNCs [60] deal differently with the topic of fault current in different countries. Some countries (ex. [14]) are already moving forward to a more detailed specification of requirements, including the extreme speed of operation (5 ms). This (5 ms) is adopted in the GB specification of the Stability Pathfinder 'Draft Grid Code–Grid Forming' [14]. Much work still remains in terms of specifying and agreeing on the desired response in the new context of high penetration of PEIPS.

2.2.3 Sink for harmonics

Key points summary

Definition: Provide a passive, damping response in the harmonic frequency range using harmonic current flow with the effect of improved voltage quality at the point of connection. The characteristic could be inductive, similar to a synchronous machine, or inductive-resistive, providing superior performance to a synchronous machine.

Allocation of current-carrying capacity to this function:

- Current-carrying capacity (headroom) is required to inject harmonic currents at required operating points.
- THD vs. individual orders: The current headroom must be appropriately distributed across the relevant harmonics. Synchronous machines' harmonic impedances increase linearly with frequency.
- Depending on the voltage level of the point of connection: the lower the voltage level the higher the planning level for voltage harmonics.

Prioritisation:

- Power quality is more of a concern in steady-state. Thus, this feature should receive lower priority than dynamic aspects such as Fault Ride-Through (FRT) or frequency support.
- As a result, the current headroom could be used by other features when they are active.

(Fair) Share of contribution:

- A proportional sharing of harmonics damping between many units is both necessary and desirable.
- Both the physical impedance (filters, transformers) and additional virtual impedances should be considered to utilise allocated headroom accordingly and provide similar characteristics for physically different units

Reference [23] contains an example laboratory implementation of the above and [14] section ECC6.3.19.3(x) contains a draft non-mandatory Grid Code specification.

Identify relevant frequency range: e.g. < 2 kHz

Performance

Reduce voltage harmonic content at the connection point by providing a current path for non-fundamental frequencies up to a limit of e.g. 2 kHz. The harmonic impedances of synchronous machines are inductive, enabling the flow of harmonic currents and thereby damping through the resistive properties of other components. Inverters could mimic the inductive behaviour of synchronous machines, or, in the lower end of the proposed frequency spectrum, provide inductive-resistive behaviour with increased damping compared to synchronous machines [67].

The required current flow is to be drawn from an allocated headroom, which must be available for an indefinite time to permanently provide damping in steady-state conditions.

Impedance may be increased to limit harmonic currents into the equipment (limit headroom), whenever the harmonic voltage levels would lead to current flows exceeding the allocated headroom, or when other features of higher priority impinge on the available headroom. Features of higher priority include those used during contingencies.

The headroom must also be allocated across the relevant harmonic frequency spectrum, to cover cases where damping cannot be provided sufficiently for all orders of harmonics. The harmonic impedances of synchronous machines increase with frequency, indicating a proportionally higher current allocation for lower frequencies.

The damping provided could be proportionally shared according to the power output level of the involved units. A combination of physical and virtual impedances could be used to compensate for variations in physical impedances.

This performance stands in contrast to typical grid code requirements to-date as well as the standard IEC 61400-21 [68] for measurement and assessment of power quality for wind turbines, which focus on harmonic content in current emissions of inverter-based generation units rather than on voltage harmonics. Requiring voltage harmonic compensation will inevitably induce variation in the harmonic current emission of the inverter-based unit [69].

2.2.4 Sink for unbalances

Performance

Considerations for unbalance affected by reduction of NPS sinks from decreasing number of SGs are in many ways similar to above considerations for harmonics.

Provide low NPS impedance. The NPS impedance may be increased to limit the negative sequence current. For a draft national non-mandatory Grid Code see [38] section ECC6.3.19.3 (xxi) and for laboratory implementation, see [23].

2.2.5 Contribution to inertia

The main benefit of inertia from synchronous machines is that their rotating mass provides inherently stored energy that, in combination with the voltage source characteristic of a synchronous machine, counteracts voltage angle, amplitude and frequency perturbations and therefore reduces the RoCoF in case of load steps and helps to limit voltage steps by providing a source of active power if needed.

Definitions

To appreciate the complexity of the subject of inertia it is recommended to read the definitions in the Annex 5 (Terminology and Definitions) to obtain clarity regarding inertia, synchronous machine inertial response, synthetic inertia and FFR. It is common for these terms to be misrepresented. In the power system context, the inertial response is defined as the energy exchanged between the grid and the rotor of an electrical machine in the case of a frequency event due to the rotor moment of inertia. These characteristics are defined in the swing equations by the gain and damping factors, further developed in Annex 5.2. This same framework can be used to characterise the inertial response regardless of type of converter implementation.

Performance

GFC is one method of dealing with the concern of diminishing TSI, illustrated in figure 4 in Section 1.2.1. As illustrated with the wide variety of frequency response capabilities as discussed in Annex 5, the 'inertial characteristics' of a grid forming converter need to be defined in a measurable way to provide converter designers and operators with a common language that can be used when discussing and agreeing on a particular inertial characteristic.

An inertial response, by definition, requires an exchange of active power between the grid and the equipment delivering the response whereby the total energy exchanged depends on both the event initiating the inertial response and the inertial characteristics of the equipment. For a GFC, where the inertial characteristics are given by the parameterisation of the control system, it is important to consider and ensure that the system behind the GFC has the capability to deliver the energy to match the programmed inertial characteristics across the expected operational boundaries, cf. section 2.3. Whether the additional energy can be made available by existing equipment in the plant, like rotating mechanical structures, from headroom created for PV or whether a dedicated energy storage system is required will depend on several factors; including the per unit inertial requirements versus the capability of the plant, the operational boundaries for the inertial characteristics, the expected firmness of the response, and the attitude towards allowing the extraction of inertial power to move the plant to a suboptimal operating point resulting in a lower power in-feed. These aspects are discussed further in section 2.3.

A TSO may assume that the inertial response provided by a GFC would be similar to that provided by a synchronous machine, in which a value of H would have a familiar meaning, with an underdamped response. However, when providing an inertial characteristic from a GFC a choice is now available in terms of the level of damping that is designed into the characteristic, e.g. critically damped or even overdamped. Whereas a higher level of damping would give the GFC a less oscillatory response, it also affects the rate of change of power when subject to a frequency event; and given that therefore a GFC is an actual design choice, the mentioned trade-off should be investigated to identify a sensible range for the damping level. In the converter the delivered response can either be internal damping that does not exchange damping power with the ac system or external damping with exchange of power with the external system, but which would require a differential type control on top of the low bandwidth voltage source behaviour of the GFC. These aspects are expanded on in Annex 5.2.

One major challenge when defining performance indicators for the inertial contribution of converters is to allow for different reference values due to different system needs without specifying the actual control implementation. From the manufacturers' perspective, it is important that a generic inertial characteristic emerges that can be adjusted for specific requirements. It may in future be possible to, within the hardware capabilities, vary the inertial and damping gains based on varying grid needs.

Relevant references include trial implementation in a wind farm [35], a BESS installation [16] and criteria [53].

2.2.6 System survival to allow effective operation of LFDD (Load Frequency Demand Disconnection)

The challenges of extremely rare situations (typically once in multiple decade system split events combined with high PEIPS penetration) assuming last resort (LFDD) is called upon:

- LFDD may not succeed during system splits with close to 100% PEIPS penetration of Class 1 and Class 2 capabilities, due to inadequate volume of SGs and hence inadequate system strength in the newly formed island, resulting in immediate system collapse.
- The limited ability of the running generation to provide a short window (100s of ms) of voltage, frequency and angle stability following the extreme event. Faster new services such as fast frequency control (with 0.5-1 s response time) may provide some help in this context (or at least be ready to take over the provision of support from the fastest providers such as GFC). Faster still is the potential for short duration (e.g. li-ion) storage, which already has all the necessary hardware to provide some GF capability and a high technology readiness. These low cost options should be evaluated in follow up studies first before wording requirements.

Locational issues for GFC installations are important in the provision of minimum system strength. This relates to both the general geographic spread and possibly the voltage level it is injected at. This influences the ability to provide an effective support close enough electrically to potential major transmission system splits. This is further discussed in section 2.7.

Performance

Studies [10], [12], [22], [70] have shown that a power system operated in the High Penetration range of PEIPS (60–100%) will, following a major fault & subsequent power imbalance be at risk of total collapse before the LFDD has implemented its load reduction (to roughly restore the demand vs. generation power balance). LFDDs are set to operate at low frequencies in stages (in CE starting with load disconnection of stage 1 (5–10% of total demand) at 49.0 Hz). Study [70] demonstrates how, even close to 100% PEIPS, a most severe system split could be survived by both islands in a two way split, even with a massive imbalance, if a certain level (indicatively 30%) of GFCs is introduced. This study was based on a current capability of 1.5 pu reducing to 1.25 pu in 80 ms. The other 70% split 50/50 between Classes 1 and 2B would allow system survival with up to 30% or possibly 40% imbalance. This level of capability is reflected in the draft non-mandatory national Grid Code for Grid Forming capability [38], at the start of a tendering process for delivery respectively from 2020 [39] and from 2023 [40].

GFCs which additionally provide inertial support typically (i.e. assuming design limits are not breached) operate as a voltage source behind an impedance whose magnitude phase and frequency only change slowly in response to events. Consequently, the only parameter which normally changes rapidly is current. The currents are therefore determined by the network and not the convertor control systems. Any given switching event or fault has little or no instantaneous effect on SG rotor and GFC internal operating angles. However, such events do typically result in large changes in bus bar angles (vector shifts), which leads to the subsequent changes in P, Q, V, I and frequency. In the case of system collapse, [25] and [71] opens up for GFC-based support of restoration.

There is some evidence – [10], [12], [72] – to indicate that grid forming technologies with limited inertial capacity (equivalent H) or headroom (i.e. the ability to increase power output before hitting power limit) are still more beneficial to grid stability than conventional vector current control convertors. Placing convertors in GFC mode could therefore be more beneficial to grid stability than leaving them in current control mode of operation, even if they are close to their maximum power output or have little capacity to provide significant equivalent inertia [12], [58].

Further studies for CE within ENTSO-E in a Memorandum entitled 'Minimum required inertia for Continental Europe' [55], [45] have explored the relationships of key LFDD parameters for system survival following system splits with various degrees of severity (imbalances from 10% up to 40%). This has not yet been turned into a target value. Further analysis of system splits for CE based on marked data is covered in [73].

To ensure power systems can survive, at least in part without total collapse under these very rare most extreme operating conditions (such as large-scale system splits, e.g. as 4 Nov 2006, see Figure 8), distributed fast acting dynamic support for a range of stability challenges (frequency, voltage and angle) is needed. These have been delivered in the past mainly by SGs. When SGs are not in operation, alternative means are required to undertake these tasks. Studies indicate there is the ability to avoid system collapse using very fast performance as provided by GFC [15], [72] converters in adequate volume and with adequate geographical spread (close enough to the location of the split).

Grid Operator System Studies should consider the grid's ability to survive a system split or generation loss scenarios and determine minimum necessary peak active and reactive power output and minimum necessary energy output with suitable control models. Realistic future penetration scenarios should be used (see section 1.1). Low cost solutions focused on control system changes incurring as little as possible extra hardware cost (see below) should be considered first in these studies (e.g. within 1 pu current for new PEIPSs assuming no retrospective implementation) and higher cost solutions (with >1 pu and/or even retrospective application) should only be added subsequently if necessary. It should be noted that the 2019 wind farm GFC trial [35] was implemented retrospectively to a 2016 installation.

An RMS type simulation can be sufficiently accurate [70], [72], although increasingly TSOs are finding that these may be optimistic in the context of the limits of stability when the penetration approaches 100%. An EMT type simulation may be beneficial for RMS method validation but practically challenging to implement in an operational environment. To support the grid during such scenarios, near instantaneous holistic support are required (covering the variety of services encompassed under the heading GFC), especially near the split location.

2.2.7 Prevent adverse control interaction

When a power converter is connected to the electrical grid, the overall network resonances vary because of: (i) the connection of the converter passive components and, (ii) the impact of the converter's active behaviour.

The interaction between the network resonances and the active behaviour of the converter is characterised by the natural frequencies of the network and the damping provided by the network, other generators, loads and the converter, which varies with every operating condition.

Electromagnetic natural frequencies appearing within a region in which the converter presents negative resistance behaviour may result in instability if the network itself does not provide enough damping to compensate. A generic example composed of a system with a VSC and a network with a given frequency-dependent behaviour is shown in the Cigre WG B4.67 brochure [74]. The control dynamics together with interaction with the network (represented by the Thévenin impedance Z_h) are shown in figure 9. The reduction of the complete VSC to an equivalent admittance is also illustrated in figure 10.

The connection of the converter to the network results in new resonant points determined by the frequencies at which the impedance curve of the converter crosses the frequency dependent grid impedance. The amplification factor is dependent on the angle difference at the crossing point. The closer to 180 degrees the angle difference is (between the converter and the grid frequency dependent impedance), the more amplified the resonance will be.

The stability phenomenon described here is related to small signal disturbances in a wide frequency range. For this reason, the terms ‘harmonic stability’ or ‘super synchronous instability’ are sometimes used. Contrary to small signal rotor angle stability, the interaction is not between the power system and synchronous machines, but between converters or between converters and the grid (frequency dependent grid impedance). In addition, sub-synchronous control interactions need to be similarly considered. To capture the nature of the phenomenon, the grid connection point frequency dependent impedance, as well as the power converter frequency dependent impedance, must be described in a larger frequency range [75], [76], [77], [78], [78], [79]. The problem may, in a high PEIPS context, include the description of the system reflecting an active network.

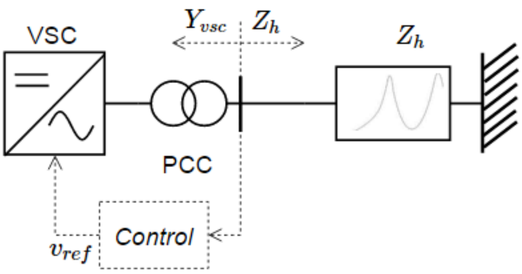

Figure 9. Example of a network composed of a VSC and a frequency-dependent AC system for the study of control interactions.

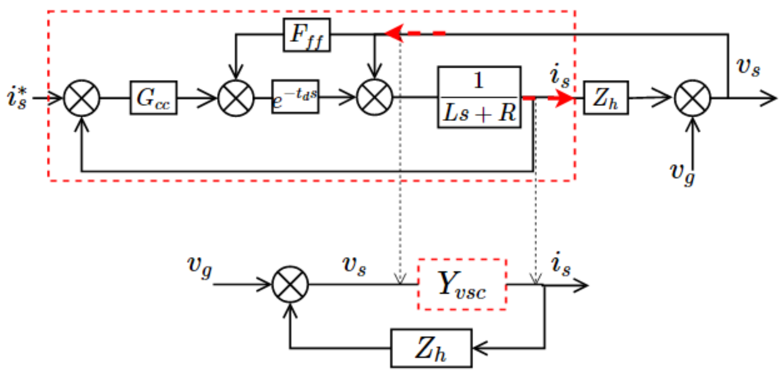

Figure 10. Dynamic interaction between the active VSC impedance and the network harmonic impedance.

Besides the extreme case of instability, resonances coinciding with this region may also result in sustained oscillations for several seconds with corresponding over-voltages and other adverse effects. Current work on terms & definitions: Cigre WG C4.49 'Multi-frequency stability of converter-based modern power systems'.

Performance

Converters are never passive (neither are synchronous machines). As the energy storage in converters is smaller compared to synchronous machines (inertia), the power control loops of power converters need to be faster for its protective (survival) and own stability purposes, thus resulting in a broader control bandwidth.

- To define performance requirements for converters, the power system needs to be analysed across the frequency range. Resonances due to passive elements (e.g. cable capacitances and transformer inductances) or active elements (other converters) pose a risk for control instability if they fall into the control bandwidth of the converter i.e. the frequency range where the converter is active. Requirements have to be determined for a specific system. One view is that 'a general specification, which avoids control interaction and resulting harmonic over-voltages in any situations', might be very conservative and impossible to fulfil. A contrary view in [38], [72] advocates a bandwidth limitation (5 Hz – 1 kHz) over which GFC control should exhibit a Thevenin source behind an impedance type behaviour in order to ensure stability for varying network topology over time and dramatically vary the short term connection of generation. This control limitation specified in the draft GB Grid Code for Grid Forming [38] mirrors SG excitation control requirements. It has a secondary aim to ensure that rms based stability studies remain meaningful in the day-to-day system operation environment. The effectiveness of this methodology in terms of delivering certainty of stability is under review [80].
- Optionally, damping can be provided in a specified frequency range (active behaviour with sufficient phase margin). This is related to the requirement for reducing harmonics in the system, outlined in section 2.2.3, although the latter mainly refers to steady state.

Study

The list below relates to the testing of systems with different system sizes (the extent of required studies decreasing from systems with a large number of converters to systems with only a few converters).

- Small-signal stability analysis. For power systems of nontrivial size, modal analysis is most conveniently carried out using a state-space representation of the system dynamics. Defining the mode frequencies and damping in this way is usually the first step in modal analysis. To determine the degree of participation of individual state variables in each of the modes, mode shapes and participation factors are useful. Contrary to small signal rotor angle stability, for control interaction the power system must be described in a wider frequency range.
- Impedance-based stability analysis in the frequency domain. This is a small signal analysis approach. It is especially of interest for the analysis of one converter against a larger system with many involved active devices. The methodology to assess the stability of two active networks is under review. Discussion on this methodology is given in [75], [76], [77], [81], [78].

- RMS-simulation (dynamic phasor representation, classical stability simulation type) may be an option for the analysis of large systems, as long as the effects to be analysed are controllers possibly oscillating against other controllers but not against passive network components, and as long as the frequency range of interested does allow a steady-state representation of passive network components. Special care has to be taken for sufficient modelling, as the models of controllers usually implemented for RMS simulation are typically simplified, for example only positive sequence representation, measurement filters and measuring value converting only represented by a simple PT1 block. Model validation is of crucial importance.
- EMT-simulation (no real-time required) with validated models (or even with models which have the firmware of the device embedded, Software-In-the-Loop [SIL] and Dynamic-Linked-Library [DLL]).
- Real-time simulations (Hardware in the Loop [HIL] or SIL).

Testing procedure

A relevant testing procedure is provided in standard [82], [83] for railway supply systems, and is described below. Such systems feature a limited number of involved parties (SOs, network users, manufacturers) and converter types. Its applicability for large transmission and distribution grids with many stakeholders and large numbers of different converter types and sizes needs to be assessed in practice.

The compatibility study, or compatibility test, is a process to demonstrate the compatibility of the new element with the existing power system. It comprises the following steps:

SO:

1. Plan for compatibility check: The plan for a specific compatibility check when introducing a new element in an existing power system defines the scope of the analysis, and the precise tasks and responsibilities. The plan shall be agreed between all parties involved. The SO shall be in charge of the compatibility study.
2. Characterisation of existing power system: Characteristics of the existing power system, information relevant to the compatibility with the new element. Existing power system also mean future infrastructure changes as foreseen by the SO.
3. Characterisation of existing converters operating on the network. If future expansion with further converters is planned, the study may include them, as proposed by the SO.
4. Characterisation of existing operation conditions. If future operating conditions are foreseen, the SO may include them in the study.
5. Characterisation of overall power system: This is the combination of the information from steps 2, 3 and 4. It may be necessary to define different scenarios.
6. Theoretical analysis of overall power system: Investigation of compatibility aspects for different scenarios. In a first step: confirm compatibility of the existing system. In a second step: test potential new element.
7. Acceptance criteria for new element: The result from the theoretical investigations in step 6 is the particular acceptance criteria for a new element. The particular acceptance criteria must be understandable and measurable when designing and testing a new element.

Manufacturer of the new converter:

8. Design / Engineering of new element, considering also the acceptance criteria defined in step 7.

9. Characterisation of new element: The new element shall be modelled with respect to its compatibility with other converters and the power system in general. The model shall be validated in step 15 below.
10. Theoretical analysis of new element: At an early stage of the design, a theoretical analysis, e.g. using computer models, shall check that the new element can meet the acceptance criteria.
11. Testing in lab (HIL): Once the new equipment is built, it shall be tested on a test system to verify that it meets the acceptance criteria as predicted by the theoretical analysis in step 10. This set of tests can be part of a type test of the new element.

SO or third party in charge of compatibility study:

12. Test plan for compatibility study: A plan shall be made to define the tests necessary to confirm as far as reasonably possible: 1) that the new element meets the acceptance criteria; 2) to ensure that the test reflects the reality. The tests shall also demonstrate the correctness of the simulations done in step 10 and shall be limited to critical cases.
13. Testing in lab (HIL): Tests will be performed on a test system. These tests shall demonstrate that the acceptance criteria are met. A failure to meet the acceptance criteria means necessary modification of the new element. This series of tests is part of a type test of the new element. The tests shall also demonstrate the correctness of the simulations done in step 10 and shall be limited to critical cases.
14. Tests on real power system: Tests on the real system shall give confidence that the acceptance criteria are sufficient to guarantee compatibility within the system after introduction of the new elements. If these tests show compatibility problems despite the compliance of the new equipment with the acceptance criteria, and after a check that the test conditions were the same as those simulated, this means that the acceptance criteria were not sufficient. If this is the case, an iterative process shall take place between involved parties to find the necessary compromise to achieve compatibility. This set of tests is part of a type test of the new element. The tests shall demonstrate also the correctness of the simulations done in step 10 and shall be limited to critical cases.
15. Tests confirm compatibility: If both sets of tests in step 13 and 14 are successful, then compatibility of the new element with the existing system has been demonstrated. This shall be documented in a compatibility report.
16. End of compatibility check: With the successful completion of the compatibility study, the new element becomes part of the existing power system. The responsibility for the compatibility case no longer lies with the supplier of the new element. Any problem occurring after will be the subject of iterative work between parties to find the necessary solution to achieve compatibility.

For large transmission and distribution grids with many stakeholders and large numbers of different converter types and sizes, the procedure described above may need to be simplified. Possible simplifications can be:

- Grouping of typical power system characteristics (points 1–5 above), based on following aspects: voltage level, expected mean electrical proximity of converters, types of converters installed, first resonance frequency and system impedance angle at fundamental frequency (natural damping of grid).
- Standard acceptance criteria (point 6–7) for the new element depending on the typical power system characteristics described above.
- Standard test plans (point 12) and test systems (point 14) for the set of compatibility tests.

Based on such a simplified approach, the compatibility design and testing only comprises point 8–16 above. The combination of typical power system characteristics and standard acceptance criteria can be described by equipment classes. After successful type testing, the choice of equipment for use in the power system can be made based on the equipment class. If possible, incremental definition of acceptance criteria could be used, so that equipment suitable for a higher class is automatically suitable for a lower class.

The definition of equipment classes and standard test plans and test systems may need to be periodically updated to reflect the development in power systems. In this case, a procedure for dealing with legacy equipment should also be determined.

From a TSO point of view, perhaps moving from modest PEIPS penetration (<60%) towards full penetration (100%) with 100s or even 1000s of elements, the above method may be less suited than in considerations of one or a few large elements (e.g. HVDC connections). Limitations of skilled study resources are likely to make full implementation impractical. Therefore, TSOs may increasingly be seeking control solutions that give greater inherent continued stable operation under a wide range of conditions including future higher PEIPS penetration through additional connections and also weather-related different operating conditions. It is hoped that GFCs may contribute to building confidence in compatibility over a much wider range of conditions.

2.3 Operational boundaries for GFC performance

The performance of a GFC during a grid event, where an exchange of active and/or reactive power between the converter and the grid is initiated, is dependent on the grid forming characteristics being supported by the converter hardware in terms of headroom for the additional current and availability of the requested active power in the context of the actual operating conditions. If the converter has no headroom for the requested current, the control system must adapt into a protective mode to avoid damaging the power hardware, which means rejecting the exchange of active and/or reactive power that the grid event initiated. At this moment, the characteristics of the power converter will change, the bandwidth will increase, and a control targeting control of current will be initiated. For grid events involving active power there is also the consideration that the power converter must be able to source or sink the energy as requested by the grid event.

It is the grid that is effectively exchanging active and/or reactive power with the converter where the amount over time is given as a function of the characteristics of the event and the parameterisation of the GFC. That is, for a GFC to retain its grid forming characteristics during a particular grid event independently of the pre-event operating point of the GFC, the event must be within the limits that the GFC was designed for. Operational boundaries will here be used to describe the range of conditions for the power system within which the GFC is expected to retain its grid forming characteristics. The operational boundaries must be defined by the entity, e.g. TSO, that is requesting/purchasing the grid forming characteristics and include frequency range, df/dt, voltage imbalance and phase step, and may be chosen more narrowly than the requirements for staying connected. Care should be taken when outlining operational boundaries to ensure a level playing field between different sites and technologies, as there is clearly a cost aspect involved with the delivery of grid forming characteristics, cf. section 2.4.

The hardware requirements for a GFC are given as a function of desired grid forming performance and the operational boundaries within which the grid forming characteristics should be operational. Inertial response is, in section 2.3.1, used as an example as both current and energy considerations apply, but other grid forming characteristics can be similarly treated.

Selecting very wide ranges for the operational boundaries means that all the GFCs retain their characteristics during more extreme system conditions and thereby help the power system ride through the event, but it also means that more current headroom and larger energy sourcing capabilities are required, which increases the cost related to converter power hardware. Opting for narrower ranges for the system boundaries to keep the cost down implies that some or all the GFCs change characteristics during the event into a protective mode, thereby leaving the power system without the support previously provided by the GFCs. Detailed contingency studies are required to assess the trade-off between system properties (e.g. range of ability to survive), GFC capability and cost.

In the above, no assumptions have been made regarding the source of any additional active power that is exchanged with the grid due to the grid forming characteristics. The reason for this is two-fold:

1. The requirement for active power exchange will, as discussed above, depend on both the desired grid forming characteristics and the operational boundaries within which the characteristics should be preserved.
2. Power converters are used as an interface between the power system and other equipment performing some primary function for a wide range of applications and technologies with different inherent capabilities and properties.

The energy must be available when required by the grid for the grid forming characteristics to be preserved, but the source of the energy can be subject to commercial optimisation considering the actual requirements and the inherent capabilities of the plant. To deliver a given requirement of power versus time profile, different technologies may choose to:

- utilise inherent power overproduction capabilities in the plant,
- move the operating point of the plant to create capability for overproduction, or
- install energy storage to create capability for additional power in parallel with the primary function of plant.

The choice will be dependent on both the inherent properties of the plant and the requirements for overproduction. Here, higher requirements, i.e. power, energy and rate of change of power, and firmer requirements, i.e. same level of response, is required irrespective of the operating point of the plant and will likely encourage solutions with dedicated energy storage. If a power generator is operated with maximum power point tracking, extracting additional active power implies that it will move the generator away from its optimal operating point, which will then reduce the maximum amount of power that the generator can physically produce. The option of extracting additional power therefore comes with the *cost* of a reduced power production capability post-event. This has been studied extensively for wind turbine generators and is often referred to as the 'recovery period' [84].

One possible compromise which may be worth considering in the future is the use of headroom (tracking a fixed level below maximum power). Enabling could be limited to times when PEIPS output is above a critical level (e.g. 70%), when the system stability otherwise would be exposed. During these periods, experience shows that the market value of the RE production is low, even sometimes negative, although legacy RE remunerations may be different. At other times normal maximum power tracking could be allowed for wind and solar PV [28].

2.3.1 Example: inertial response

The expected inertial response of a converter interfaced unit to a grid event will be inherently interactive with the grid. That is, it is the characteristics of the grid voltage, i.e. phase and frequency that determines the resulting power that will flow from the converter interfaced unit having a set of pre-defined inertial characteristics.

The response requirements for the converter can be broken down into a disturbance in energy and a peak current required for exchanging the disturbance energy. A converter with a given set of these properties can only be configured for a specific inertial characteristic when the boundaries for required survival of the grid (in context of rare extreme events) that it is connected to are known (the network requirements). That is, it is the worst-case grid characteristics (conditions for which the system is required to survive) that define requirements for disturbance energy and peak current (or power). For events out of those operational boundaries, it is expected that the converter interfaced unit delivers a non-linear response, with the main intention of ensuring that its hardware limits are respected, although TSOs are likely to prefer a limitation of the GFC response rather than a total mode change.

The energy that a synchronously rotating mass exchanges with a network when subject to a steady state change in rotational speed is given by the change in stored kinetic energy between the two rotational speeds. The analogy to a GFC equipped with an energy limited source, e.g. a storage system, is that it is therefore necessary to know the frequency range (operational boundary) in which the inertial characteristics should apply in order to design the required capabilities into the system; an example of this is the draft national non-mandatory Grid Code [38], see section ECC6.3.19.3(xi).

The power that the inertial energy is being released with is a function of the RoCoF and the damping of the inertial characteristics. This has two important implications for the design of converter units that are to possess such characteristics: 1) a sufficient current window need to be designed into the power converter to allow the power to be delivered on top of its pre-event operating point, and 2) the energy source that is delivering the inertial power must support this power level and, additionally, the rate of change of power, which is strongly influenced by the damping levels of the inertial characteristics.

In summary, if the characteristics of the worst-case events and the requested or required inertial characteristics are known, the hardware for converter and the energy source can be designed accordingly. Alternatively, if already existing hardware is being deployed in a power system, the inertial characteristics of the control software need to be configured to respect the hardware limits for the design events of the power system.

2.4 Cost Considerations

Below, preliminary considerations only reflect hardware costs. Development, operational and servicing costs, patent and licensing related costs, and certification and compliance testing costs will have to be considered as well and depend on a variety of factors.

Grid forming converter control is fundamentally different from the control that is commonly employed today and will, considering the general maturity level mid-2019, require a significant R&D effort from converter manufacturers to develop their technology readiness level to today's level for current control. This includes:

- control stability and interaction
- hardware development (both converter and, when required, energy storage)
- hardware re-dimensioning (both electrical and mechanical if additional stress levels are imposed as a result of the grid forming operation)
- development and validation of client user models
- grid compliance testing and certification
- assessment of the wider impact on equipment design
- quantifying any impact on equipment capability across the entire operational envelope
- concept maturing and runtime

A GFC installed for system stability purposes can be developed as a standalone converter serving only this purpose or the grid forming control and any additional hardware capabilities can be integrated into converters that serve additional purposes, e.g. battery systems for fast frequency reserve or power producers such as PV or wind turbines. Common to both concepts is that energy and current headroom, as defined by the required grid forming performance and the system boundaries, must be allocated if a firm response is required. The cost for the additional hardware will, as discussed in section 2.3, be highly dependent on the required grid forming performance and the operational boundaries within which the characteristics should apply. As performance is generally assessed at the Connection Point, a choice arises in terms of delivering performance from the equipment performing the primary function or by adding centralised equipment at the substation [24]. Whether it is most cost effective to integrate the grid forming functions into a power converter serving other duties will likely depend on the balance between savings from utilising existing infrastructure and design work, set against the difficulty in integrating the grid forming functions with the primary duties of the converter. Potential savings include:

- Re-use of components with inherent short-term overload capability such as power transformers and cables
- Additional civil works are much less than that required for a complete stand-alone GFC
- Potential synergies between hardware installed for grid forming services and equipment for primary duty

Potential challenges include:

- Difficulties in integrating the grid forming functions with the primary duties of the power converter
- Additional hardware for grid forming services poses a potential risk of additional downtime which affects the primary duties and thereby the revenue stream
- Ability to sufficiently isolate the structural components towards the power disturbances caused by the active power exchange with the AC power system

The requirement for additional electrical hardware for higher current rating and, potentially, an energy storage system is one of the sources of added cost for a GFC and is what enables the converter to retain its grid forming characteristics across a wider range of operational boundaries. As discussed in section 2.3, there is a decision to be taken about how wide the operational boundaries should be; where the trade-off is between the cost of the GFC and the predictability of the response. The impact in terms of system support and operation from operating a GFC without additional hardware capability to support the grid forming characteristics is not well understood. On the one hand such GFC would support the power system operation when not in limit, but would, on the other hand, have a significant change of characteristics whenever it went between its grid forming mode of operation and its current or power limiting mode of operation, which would make stability more difficult to assess and, additionally, make the response to grid events less predictable and, hence, less dependable. It is suggested that careful study should be given to what level of system support and security the geographical distribution and the natural statistical variation of operating point for such limited capability GFCs would provide; and whether the associated trade-off between cost savings and risk profile is favourable. Further examination is required of the benefit of a more gradual boundary transition which could arise from the chosen GFC control strategy.

2.4.1 Considerations for wind power plants

Cost consideration for wind power plants must reflect development costs and additional capital cost due to design changes compared to current products, as well as operational expenses due to additional component maintenance and wear and tear or component replacements over the lifetime of the product.

Development costs are significant. Wind power plants with built-in grid-forming capability are not currently available as off-the-shelf products. Rather, the technology is at a demonstration or early prototype stage [34]. Wind power plants are subject to rigorous certification procedures and are faced with customer expectations of very high availability, reliability and high lifetime, typically 20 years or more. As a result, development efforts must achieve a very high maturity before widespread product rollout. This typically involves several stages of testing at increasing power levels, as well as field testing and validation with significant investment of time, manpower and measurement equipment, as demonstrated in [35].

Additional capital costs will be incurred depending on the operational boundaries that are relevant for the application. Quantification of boundaries, in particular with respect to current capability of the power converter and energy buffer size, is required for a detailed assessment of the capital cost implications. Additional energy storage is very likely required under most operational boundary scenarios, because wind power plants are designed for cost-efficient energy transfer from the wind into the power system. They typically do not include significant internal storage apart from the rotational masses in the wind turbine rotor. However, the mechanical drive train is often subject to strict limitations of the dynamics that may be imposed on it from the electrical system and may therefore not satisfy the requirements for the storage elements, either in terms of capacity or dynamics, or both. The location of the storage elements and additional converter capacity may vary between solutions and may incur additional civil works capital costs.

Finally, additional components such as storage elements may add to operational expenses due to inspection intervals or replacement schedules. There may also be additional constraints in terms of operational control of the wind power plants, as they may not always be allowed to operate in the most economic fashion, for example if a reserve power must be kept. This may reduce income from feed-in compensation and may be seen as an additional operational expense.

2.4.2 Considerations for PV plants

State-of-the-art PV-systems are controlled to operate in the maximum power point (MPP), depending on the irradiation. Effective grid forming control will provide with sufficient power and energy reserve to respond adequately to abrupt voltage phase angle changes. Providing this power reserve is linked to curtailed operation and therefore loss of generated energy and reduced economic income. To achieve such a power reserve continuously would require significant hardware effort (e.g. sensors) and / or new control designs, especially for small scale applications.

Without storage, a <1% cost increase will yield significantly less performance compared to wind in terms of providing additional power; since storage is minimal (only a DC link depending on design and control strategy), significant additional power may only be provided over a few milliseconds. In terms of fast reduction of infeed power, very high dynamics are possible since there are no moving parts / rotating masses. In [28], operation with target headroom below the maximum available power is demonstrated. This should be examined further in the context of GFC control for solar PV.

Technology readiness is therefore mainly linked to PV combined with storage (BESS), with the BESS converters providing GFC controls, see [85], [59], [43]. In some countries, e.g. Germany, new PV in the future is expected to contain storage. A marginal cost would be incurred for reserving part of its capacity to deliver a dependable GFC service.

It has to be considered that small PV / storage systems especially are required today by some DSOs to provide a reliable LOM mechanism in order to avoid unintentional islanding. Grid forming controls in principle contradicts this objective. New, more fit for purpose, LOM protection based on communicated reference signal between GPS synchronised units has been developed by the University of Strathclyde, but has so far not been adopted by the industry.

Beyond a 5% cost increase will likely yield more performance, as with this investment storage can be added. The performance per euro spent is expected to be higher for PV and storage compared to wind, as size and weight indirect cost is higher for wind (where components are in tower and nacelle). However, costs significantly depend on expected energy to be stored and the duration of additional power provision.

2.4.3 Considerations for Grid Scale High Power Storage (lithium ion or comparable technology)

With respect to storage systems, there is technology readiness, as commercial solutions for microgrids exist [59], [43]. MW installations exist predominantly in smaller systems with very high RE penetration and as alternatives to running diesel generators, [85]. These may have to be adapted to fulfil all the needs of interconnected grids. A 30 MW interconnected grid installation with GFC control already exist in South Australia [16].

Exclusive access to headroom (to reserve a part of the continuously additionally available power for GFC) and storage for GFC capabilities (not used for other purposes) versus shared use with priority allocation is a topic not yet addressed.

In the case that a shared use is assumed, costs mainly evolve from the need of substantial change to the control system (which some battery converter suppliers already offer commercially for island applications). Therefore, costs result e.g. from additionally needed development, testing and verification of the systems. On a case-by-case basis, costs resulting from different load profiles of the battery need to be assessed. Rated power would be available instantly for up to >30 minutes.

Just like the application of GFC on PV-systems, mass application of small-scale storage systems in distribution networks (including potentially available V2G applications) would have to deal with the possibly contradicting requirements of DSOs and additional costs in hardware.

2.4.4 Considerations for HVDC installations

Limited GFC (addressing some of the capabilities in section 2.5) has been implemented in HVDC systems in several cases [79]. However, an HVDC system consists of at least 2 terminals; having GFC in both terminals has not been implemented and is very challenging because one terminal needs to be controlled fast to ensure DC voltage stability. Further challenges arise from the fact that short-circuit strength at transmission level will vary much more than for other converters in the distribution level.

HVDC installations connecting different synchronous areas, even if only one terminal is in GFC, can offer significant advantages, since inertial contribution can be shared. However, providing inertial contribution only from the terminal HVDC converter without supply from the remote terminal (e.g. in the case of an HVDC system with all terminals embedded in the same synchronous area), is very challenging, since only marginal energy for around one cycle can be drawn from DC capacitance (similar to PV) [86]. For significant cost increase, storage or additional capacitance on the DC side could be theoretically considered to offer such capability (similarly to PV). Increasing the DC capacitance in HVDC valves is very challenging due to the already very high currents.

With respect to providing a sink for harmonics and avoiding adverse control interaction, no additional cost applies for hardware or software, as long as the stability of the converter control over a larger frequency range and for different characteristics of the power system is already ensured by the design (which may be particularly challenging in the highest PEIPS penetration). This might not be the case nowadays for converters interfaced to the distribution grid. If the converter must provide additional damping for the power system in order to avoid control interactions, only small power modulation is needed to damp out small signal oscillations. This can be achieved without additional dimensioning of the converter by temporarily reducing its fundamental-frequency power output, similar to when riding through faults. In special cases, e.g. for capacitive networks, the introduction of (low-pass) passive filters may also be required; this could also be realised by the system operator/owner within the network. Minor cost for software development is necessary. If the converter is dimensioned to act as sink for harmonics in steady state, higher contribution for additional damping can be achieved at the same time if requested by the TSO to ensure system stability.

Additional cost applies for project-specific compatibility tests. Such cost can be reduced if typical network characteristics and acceptance criteria can be assumed (standard classes), although this may again be challenging near 100% PEIPS penetration. Due to the potential larger ranges to consider in standard classes, the control design may be more challenging, however.

2.5 Must-Run Units

Here this term is used to cover all power sources running without being in merit commercially and are obliged to stay connected, with the sole purpose of providing the capabilities described in section 2.2. Different arrangements have been made over time to cover this. Some countries used to do this on a rule basis, e.g. for system strength / stability reasons a minimum number of synchronous units may need to be run. Increasingly, this objective is achieved through AS and use of SCs, e.g. in which the commercial substitution of some RES with SGs is undertaken to create minimum system strength.

Combined heat and power is a significant source of generation in some countries, which may continue to run even if out of commercial merit, because of the continued demand for the heat. These must-run units can in part deliver the various system strength services. In Ireland, there is a market for auxiliary services which includes inertia, therefore it is no longer just must run but also market driven units providing stability support.

2.6 Synchronous Compensators / Condensers

SCs have been increasingly considered as one possible solution for challenges raised by the higher penetration of power electronic sources. As future PEIPS are expected most likely to be connected to more remote areas, it is therefore an option to enhance the system strength at these remote areas by means of SCs. Existing redundant SGs could be converted to SCs or new planned SGs could be equipped with clutches to enable isolation from the mechanical prime mover. Moreover, the installation of flywheel systems to SCs would provide both voltage and inertia support to the system.

Similar to SGs, SCs are able to:

- provide MVArs and synchronise Torque between SGs and SCs
- provide effective support for grid restoration
- temporarily run as generators (only if a coupled turbine is available)
- contribute significantly to short-circuit current infeed
- contribute to small signal and transient stability act as ‘sinks’ to correct low order system harmonics as well as phase unbalance
- participate in providing instantaneous inertia
- provide voltage support and dynamic regulation by generating or absorbing MVArs and by doing so participate in voltage regulation and support voltage stability. High inertia SCs with H constant of up to 6.5 s are available on the market and can provide up to 0.5 GWs inertia

SCs can easily work together with quick dynamic MVAr providers such as STATCOMs, HVDC links, wind or solar converters as well as energy storage converters. This ‘coordination’ of SCs with faster dynamic devices is of importance for multi fault situations.

2.7 Spatial Distribution of Grid Forming Units or Must-Run Units

Studies [10], [58], [70], highlight the need for spatial distributing of the GFC controls as equally as possible across the power systems’ area. Spatial distribution is required in the context of retaining stability on the occurrence of very large angular jumps, e.g. due to system splits, as well as to ensure that PEIPS survive close to severe fault events.

GFCs which additionally provide inertial support typically operate as a voltage source behind an impedance (assuming design limits are not breached) whose magnitude phase and frequency only change slowly in response to events. Consequently, the only parameter which normally changes rapidly is the output current. The currents are therefore determined by the network and not the convertor control systems. Any given switching event or fault has little or no instantaneous effect on SG rotor and GFC internal operating angles. However, such events do typically result in large changes in bus bar angles (vector shifts), which leads to the subsequent changes in active and reactive power (P, Q), current (I) and voltage magnitudes (V) across the network. The frequency may change subsequently as a consequence of the change in power.

Having SGs, SCs and GFCs close to events, such as generator or interconnector trips, could help to reduce these vector shifts by transiently supplying power at a local level. The further away from events the GFCs, SCs and SGs are located, the greater their vector shift, as the power must be transported over greater distance. Electrical distance is expressed by impedance, which is mainly reactance X in the case of a high voltage or extra high voltage transmission system. Transporting the same amount of power over a larger electrical distance causes a larger voltage angle deviation (vector shift) because of the following equation (P= VE.Sin(d) / X). This in turn potentially leads to larger deviations in the other variables.

As the locations of the next disturbances (such as load changes, switching events, short-circuits, generator or load trips) in a power system are not predictable, and at the same time the electrical distance of a noticeable amount of SGs, SCs and GFCs should be near to the location of the disturbance, the SGs, SCs and GFCs must be distributed as equally as possible across the network area. As the electric distance between the location of a disturbance and the SGs, SCs and GFCs should be rather small in order to ensure the SGs, SCs and GFCs show a beneficial contribution to the power system, the PPM with GFCs, SGs and SCs are less valuable in the context of avoiding transmission collapse if the PPM, SG or SC is connected at medium and low voltage levels.

If an equal spatial distribution is not possible, SGs, SCs and GFCs should rather be connected in the centre of a network (resulting in a similar average distance to disturbances), than at one side of the network. Locating all the resources in one area puts the other area at greater risk if islanding occurs, as limited resources may only be available in the islanded system. Hence, SGs, SCs and GFCs should be distributed in such a way that following system split scenarios which are identified as being relevant, each islanded grid area after system split must remain with a sufficient number of SGs, SCs and GFCs.

It should be noted that in smaller power systems (island systems, micro grids) the spatial distribution is of less relevance compared to medium-sized or large power systems.

There are R&D groups established to study how distributed generators and loads may provide 'flexibility' for the network. In addition, the GB Stability Pathfinder process [14], [37], [38], [40] brings these considerations into a draft non-mandatory national Grid Code and market based procurement process.

3 Proposed Tests and Benchmarking

The concept of GFC represents a significant increase in complexity of the parts of the converter control that is subject to (external) performance specifications where inherent response capability provides an additional level of complexity for the performance validation process; both at simulation level and perhaps even more significantly when the performance of the actual equipment needs to be verified. GFCs will require the development of processes and standards for testing, validation and certification, using both simulation models, laboratory and site tests to ensure that the response satisfies the specified requirements. Implicit in that need is the standardisation of the grid forming characteristics in a quantifiable way that can be assessed from measurements, which would furthermore help avoid a situation where e.g. a GFC 'inertial response' means something different for different TSOs.

A further consideration with a GFC is that it will have two distinct modes of operation depending on whether it is operating within its current and/or power limit or whether it is in a limit condition. The need to protect the converter power hardware is not new to GFCs but is a central part of any converter control. However, the change of characteristics when entering the protective mode will, arguably, be more pronounced for a GFC. The amount of transitioning between the two modes will, as discussed in the section 2.3 'Operational boundaries for GFC performance', depend on both the occurrence of events in the grid and the chosen operational boundaries within which the grid forming characteristics should be retained as well as the control method of current limitation.

Work on standard or generic models, such as the IEC 61400-27-1 and WECC models for wind turbines and PV, is another area that would require a significant amount of work from the power community to accommodate the requirement for open and public models that exist in parts of the world. Clearly, such efforts are dependent on a consensus developing on the definitions of the grid forming characteristics.

3.1.1 Control and subsystem testing

The low maturity level of GFCs and their intended characteristics creates a need for shared and open benchmark systems with clearly defined test cases where manufacturers, academia and SOs can come together and discuss specifics of the control response. The benchmark systems should preferably be very simplistic to keep the focus on the response of the converter controller and ideally a simple Thévenin equivalent network with controllable grid voltage and grid impedance. Naturally, the minimum size of the equivalent network used in the test case is highly dependent on the characteristic that is analysed, but keeping the benchmark systems simple makes cause and effect easier to analyse.

Part of the exercise with defining appropriate benchmark systems is to develop test cases that allow the characteristics of the converter controller to be assessed across the operational envelope of the converter. The development of the test cases needs to be done in conjunction with the development of items or elements for the requirement specification; that is, if a requirement specification states a certain performance for inertial response, the test cases have to allow testing that 1) whether the response can be classified as inertial response, and 2) whether the performance of the inertial response satisfies the given requirements.

The choice between whether RMS or EMT simulations are required will at least depend on whether the study involves pushing the GFC into a limit condition and whether it involves assessment of harmonic behaviour. Aspects of the controller characteristics are perhaps more appropriately analysed in frequency or impedance domain as the converter response to a grid disturbance and reference changes.

For harmonic assessment, the converter control model could be applied to distorted grid conditions with representative harmonic impedances and the effect evaluated. The study should consider a range of background harmonics across the relevant frequency range and variations in the harmonic impedances of the equivalent system representation, as well as all relevant configurations of equipment impacting harmonic emissions and harmonic stability in the area of interest (see also section on control interactions/harmonic stability).

Power converters with low power ratings could be directly tested against a controllable voltage source in a test bench, but for high power applications this becomes impractical as well as a costly exercise. Whereas only testing the control system in a hardware-in-the-loop setup would be a lower effort approach, this would need to be developed and be accepted as a viable means of compliance testing. Work has begun within IEC61400-21-4 to investigate the possibility of doing compliance testing of a subsystem at component level instead of relying on site tests of fully rated plants. Such approaches would be interesting in the context of GFC testing.

3.1.2 Site testing

Site testing for performance validation and certification is widely used within the power industry as a tool for ensuring that the plant with all its auxiliary equipment and a specific version of control software operates according to the specifications for severe events such as under and over voltage FRT. It is already complicated and costly to test high power equipment. To include tests that involve disturbances to the voltage angle or frequency would require test equipment that is even more advanced than that used today.

Post processing of measured data from actual events would allow manufacturers and system operators to verify the performance of the equipment to the event. However, in terms of being a method for performance testing and validation there are several shortcomings, including:

- Problems with performance are only discovered after an event
  - limited usefulness for events occurring once in decades
  - it implies that equipment is already in operation before compliance with requirements was demonstrated
- High fidelity measurement equipment needs to be available on the converter installation throughout its lifetime
- The results are not easily reproducible, so improvements to the control performance cannot be validated

Certain aspects of a converter's grid forming characteristics may be assessed by injecting disturbances into the converters view of frequency and/or phase, and this has been demonstrated for a wind turbine in [34]. It is unknown whether such injections are compatible with all control designs of all flavours of GFCs and the method would require further development to allow assessment of further aspects of the grid forming characteristics.

Compliance evaluation of harmonic emission levels is an area where today's method of performance evaluation of a converter conflicts with the concept of GFCs. One of the objectives with GFCs is that the converter should act as a sink for negative sequence currents and harmonic currents by virtue of controlling the converter voltage as a positive sequence voltage source. That is, a well performing GFC could see measurements of larger negative sequence and harmonic currents as compared to a non-GFC where the converter terminal voltage could include negative sequence and harmonic voltage sources tuned to limit the negative sequence and harmonic currents entering the converter. The harmonic assessment would, as such, need to also consider the phase of the negative sequence and harmonic currents and whether the GFC is assisting the system voltage in reducing the voltage imbalance and/or the harmonic voltage distortion. The overall impact of the GFC performance to improve system voltage quality at its terminals will highly depend on the power ratio of components causing these disturbances and the GFC power trying to 'clean up'.

The ability to continuously evaluate the small and large signal characteristics of a GFC could become valuable if e.g. the grid forming characteristics of a power converter are used as a feature set that is only enabled on request by the equipment owner during certain operating conditions. To achieve that, a measurement system would be required that could estimate the particular grid forming characteristics of the converter through measurements from the converter terminals. Alternatively, GFC mode of operation could be enabled via a signal from the SO, e.g. based on assessment of PEIPS penetration.

4 Outstanding questions

There are outstanding questions not yet tackled / answered by the TG HP.

Needs for holistic GFCs and manufacturer's issues:

1. What proportion of the power sources need to have the seven characteristics in question?
    a. R&D so far suggest to get to 100% PEIPS penetration a minimum somewhere between 10 and 30% in GB and 30–40% Ireland at any time is necessary [10], [37], [51], [57], [70], [72], [87].
        i. Further analysis and practical experience is likely to clarify the need.
        ii. The answer may vary between networks, by size of the SA or characteristics of each system such as local concentrations of PEIPS and their connectivity to the rest of the system
2. Where and when will the services need to be available? Initial indications are contained in the data in sections 2. In SA GB [39], [40] and Ireland [6], the answer appears to be now.
    a. It is expected that a good spread of the capability will be useful. Does this translate into a need to add something about location, if only a proportion of new installations is required to be equipped with GFC capability?
        i. In GB an early focus is on effectiveness in Scotland [40]
    b. Rather than a proportion of new installations being equipped would it be better introduced to all new installations for a period, bringing the overall system % GFC up from 0%, until the target capability has been established?
    c. Will having some installation with a large GFC capability or having many installations with a lower GFC capability be optimal?
    d. How effective can installations delivering some rather than all the GFC seven characteristics be?
        i. Could, for example, SCs connected at transmission level provide fault infeed covering transmission concerns, while PEIPS connected at all voltage levels equipped with GFC provide the other capabilities including inertia and damping?
3. If installed deeply embedded (medium and low voltages), would GFC be effective for all the challenges?
    a. Can GFCs be connected to the distribution system without jeopardising the distribution system security and safety?
    b. Do protection systems have to be adapted [62], [63], [64] and can unintended islanding be avoided, or is a new LOM protection operating principle essential?
4. Are some types of PEIPS better suited to deliver GFC with these characteristics more cheaply and more effectively than others? Will the GB Stability Pathfinder [14] in progress deliver answers?
    a. small embedded PEIPSs versus larger units connected at higher voltages?
    b. BESS easier (lower cost) than HVDC?
    c. PV easier (lower cost) than wind?
5. Introducing GFC is a major change. Ensuring that the desirable characteristics embedded in existing designs developed over decades are not lost is essential. Can this be achieved by all technologies?
6. Minimum stored energy required for GFCs?
    a. Would the value be universal or varied across power systems?

i. P.U cost per technology?

b. Which applications can deliver this from headroom, including established by constraining when required (based on SO notification of HP operation mode)?

7 Current rating required above PEIPS active power rating?

a. P.U. cost per technology?

8 Are there any technologies suitable for modest cost retrofitting of GFC capability to existing installations?

a. Processes for continued compliance may be critical even where the physical change and cost is moderate.

b. What can be learnt about retrospective GFC application for wind from the wind farm trial [35]?

9 Would it be useful and practical to enable GFC only on SO notification (of high penetration / low system strength), having another control mode (e.g. as at present) at other times?

a. Further refined with an online change of characteristics?

10 When can cost effective practices for testing and validation (certificates) be made available for GFC?

11 Will the fault level necessarily reduce as PEIPSs replace SGs, considering network changes?

INCENTIVES / MARKET ASPECTS

12 How large is the likely market for GFC type capabilities?

13 Manufacturers need commercial incentives to proceed with GFCs. These are only likely to be in place if their customers are willing to pay a premium for the new capabilities.

a. How is a timely incentive created, visible early enough (e.g. 5–10 years ahead with medium term security) to include GFC type capability in plant specification and tendering [39]?

14 How should SOs incentivise the required capability?

a. Mandatory SO requirements for capability to be available when needed and in the right locations?

b. Market for capability?

c. If no SO direction, then should adequate capability choices made by Developers based on prospects on earnings in operation years ahead via AS be assumed?

d. What can be learnt from the wider experience (e.g. AEMO [87]) and from the design of the GB Stability Pathfinder tendering process, phases one and two [38], [39], [40]?

15 How should SOs incentivise the utilisation of the capability in operation?

a. Should there be an ancillary service for system strength?

i. Covering contributions to ensure a minimum level?
See Australian detailed requirement example from AEMO [87].

ii. Should this be split into components, e.g. those from the list of seven seen as critical for a specific network?

b. Contract capability which is always enabled?

c. Contract capabilities which are only paid and enabled via notification when needed?

d. Should creation of headroom be paid for?

e. Should the SGs also be paid for these system strength services in future?

i. At present these are only paid in context of must run / constraining actions

f. Could system strength services realistically be traded across Europe or is it too localised and too complex to make this worthwhile?

g. Could other incentives be introduced such as PEIPS Owners losing the right to compensation from SO for being constrained off, unless having the critical HP capabilities? This could be active during HP operation.

16 How can an SCs alternative best be considered?

a. Does a mix of SCs and PEIPSs prove an economic solution to adding system strength?
    i. Phoenix project in Scotland is exploring this
b. Is adding a flywheel to obtain substantial inertia economic?
    i. 70MVA unit is available with H=6s and five times increased stored energy
c. Should these be large central units or smaller decentralised units?
d. How economic and practical is the use of large decommissioned generators as SCs?

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6 Annex

6.1 Terminology and Definitions

CAPEX:

Expenditure on investment in assets.

OPEX:

Expenditure on operation and maintenance, engineering and business support costs.

Damping (synchronous Machine):

Characteristic of a synchronous machine to provide damping torque.

Damping torque:

Capability to damp periodic, subsynchronous active power fluctuations between generator and grid elements.

dq-axis Current Injection (DQCI):

A voltage source converter (VSC) in which the control software calculates the voltage that the power converter should apply to achieve a current targets to produce active and reactive power outputs based on the actual grid voltage. The control algorithm is usually based upon a phased-locked-loop and dq-axis control loops in a rotating or stationary reference frame. This is the most common type of grid-connected converter control algorithm used for existing renewables, storage and HVDC schemes.

Fast Frequency Response (FFR):

Fast Frequency Response is the ability of a grid-connected converter to provide an energy response in front of frequency event slower than the rotating machines inertia response but faster than the synchronous machine primary controller.

Frequency (fundamental electric frequency):

In a conventional power system, the fundamental frequency (of a commonly three-phase system) is related to the rotating speed of the SGs. The factor between the mechanical rotation frequency and the electric frequency is the number of pole pairs. In a conventional power system, the frequency is a state variable and cannot change instantaneously.

In a system without SGs, the fundamental frequency can be derived from the angular change of the voltage phases (phase angle derivative of the fundamental frequency positive sequence voltage) measured over one line period (if no zero-system exists, frequency, and positive and negative phase sequence components can be identified in half a line period).

In a power system without any (mechanical or electrical) inertia, the frequency can theoretically change instantaneously (as can be done with a signal generator voltage source in laboratory). Power electronics have to measure the frequency from the instantaneous values of the voltage (three phases, space phasor).

Fault level:

See short circuit power.

Grid Forming Converters (GFCs):

GFCs shall be capable of supporting the operation of the ac power system (from EHV to LV) under normal, alerted, emerging, blackout and restoration states without having to rely on capabilities from SGs.

Grid Forming Inertia:

The inertial characteristics for a GFC will here be defined in terms of the response of a single mass swing equation when subject to an imbalance. That is, a response that in nature is comparable to that of a classical representation of a SG. That is not to specify or suggest any implementation but rather to use this dynamic representation as a reference for the characteristics that are sought.

Such definition of grid forming inertial characteristics means that the converter interfaced unit will exchange power with the AC power system when subject to grid voltage angle or frequency disturbances in a manner that follows the swing equation parameterised for an agreed set of characteristics.

The characteristics are thus considered to be a subset of the synchronous machine inertial response in that only the energy released as a function between a constant or slowly varying generator back EMF and its terminal voltage that is considered.

Inertia:

In the power system context, the inertia response is defined as the energy exchanged by the grid and the rotor of an electrical machine in the event of a frequency event due to the rotor moment of inertia.

Pulse Width Modulation (PWM):

Describes the signals applied to IGBTs, MOSFETs etc. within a VSC so that the desired voltage or current is synthesised at the switching bridge. This technique is the most common method to create an AC voltage in VSC.

Point of Common Coupling or Point of Connection:

Point where the converter based device is connected to the power system

Rate of Change of Frequency (ROCOF):

The measured value of the d/dt of frequency, which itself is the d/dt of the voltage phase angle, at some point on a network. To obtain a usable value within a real single-phase or three-phase power system, rolling windows (0.5 s in NC DCC and 1.0 s in NC HVDC)/filters must be used to reject noise and other power-quality phenomena, so that the wanted ROCOF measure is observable with time delay. Use of Fourier techniques, rotor models and zero crossings all have different responses and behaviours, and abilities to reject unwanted disturbances.

Swing Equation Based Inertial Response (SEBIR):

A scheme in which a response is provided, by forming an estimate of ROCOF from system measurements, and then computing a modified active-power setpoint target.

Short-circuit power or fault level:

The short-circuit power (or fault current) is the maximum power (or current) that flows to a given point of the power system in case of fault. Usually, the short-circuit power is indicated as $S_{k.}$ More information about the short circuit power calculation can be found in IEC6909-0.

Short-circuit ratio (SCR):

The SCR is the ratio of the short-circuit power S_k of the system at the point of connection, PoC, at which an installation is connected to the system, and the nominal power S_n of the installation. SCR = $S_{k,PoC}$ / S_n
In a conventional power system it indicates the 'strength' of the system in relation to the electrical 'size' of an installation.

Synthetic inertia:

Synthetic Inertia is the ability of a grid-connected power converter to exchange energy when a frequency event occurs. There is not a standard synthetic inertia implementation, although the responses typically involve measuring the frequency and commanding the converter to temporarily increase its active power output. In the literature, several implementations of a synthetic inertia controller have been suggested, spanning from controls attempting to emulate a swing equation-based response from a frequency measurement and a derivative control, droop controllers and bang-bang controllers.

A comparable response to a synchronous machine may be complicated to deliver due to ROCOF measurement delays and filtering. As of today, the response is then better thought of as short term (seconds) frequency response that is delivered through control of the net side inverter, see FFR.

SPGM:

Synchronous Power Generating Model as defined in the NC RfG

SSCI:

Sub-synchronous controller interaction, super-synchronous controller interaction,
sub-synchronous controller instability or super-synchronous controller instability

Super Synchronous Instability (SSI):

SSI describes a condition of system wide instability at frequencies above the fundamental system frequency of 50 Hz (e.g. a few hundred Hz).

Synchronising torque:

Part of the electrical torque produced by a synchronous machine that is proportional to the electrical machine angle

Synchronous Machine Inertial Response:

Synchronous Machine Response refers to the dynamic response of a physical synchronous machine when a frequency event occurs when only the dynamic behaviour of the machine is considered (without considering the effect of the control loops).

This response can be divided into (at least) two: the inertia and the damping. The inertia is the reaction of the generator back EMF locked to the rotating mass to the angle of the voltage at its terminal, and the damping is the reaction of the damper windings to the frequency of the voltage at its terminal. It worth noting that inertia and damping response occurs simultaneously during a frequency incident and the output power of the synchronous machine is affected by both dynamics.

System strength:

The power system 'strength' can be defined from two aspects

- its impedance which is made up of generators, transformers, transmission lines and loads (usually expressed by means of fault level or short-circuit power);
    - This can be expressed as either
        - Fault Level (in MVA at connection)
        - SCR (SCR in pu of the size of installation)
- its mechanical rotating inertia.
    - This can be expressed as TSI

Total system inertia (TSI):

The inertia is expressed for a total SA or a contribution from a distinct part of the SA. The TSI can be expressed in MVAs or in pu in s by dividing the MVAs' inertia value by the total installed MVA generation capacity in the SA (or part of the SA).

True Inertia (TI):

Power response from a SPGM or GFC that is a direct consequence of network phase/frequency perturbations

Virtual Synchronous Machine (VSM):

A VSM is a controller implementation of Grid Forming Control applied to VSC that mimics all or some of the synchronous machines' dynamics. A converter controlled to behave as a true voltage source, with a virtual rotor model, tuneable values of inertia constant H and damping, and tuneable governor control loops to suit the energy source/sink to which the converter is connected. The performance of this device is closely aligned with that of a real SPGM, although the magnitude of the fault currents available is capped by the short-term current overload rating of the converter hardware. VSMs make no (or very limited) responses to unbalanced current or harmonic voltages. The converter behaves as a 'balanced positive-sequence fundamental-only' voltage set behind a 'transient impedance' (i.e. the filter impedance). Since the magnitude and phase of this voltage set is changed only slowly, a VSM mitigates unbalance, harmonics etc. on the voltages at the connection point, by sinking or sourcing currents as required.

Voltage Source Converter (VSC):
A VSC is a power converter based on forced commutation switches that exchanges energy between a DC and an AC source. As this kind of converter imposes a voltage in its AC terminals, it is known as a Voltage Source Converter. This is the most common kind of power converter for grid-connected applications. For applications in the range of the kW or MW, the most used power converters are the two-level or three-level and the MMC is used in the range near the GW.

A 'Voltage-Sourced Converter' is made with self-commutated devices such as IGBTs, IGCTs or MOSFETs and coupled to a DC bus which is held at a roughly constant voltage. This explains the origin of the term 'Voltage-Sourced' in this context, because by defining the PWM patterns at the switching bridge, one defines the voltage which is 'created' there, as a proportion of the DC bus value. This compares to an LCC device using thyristors, with an inductor on the DC bus so that the DC bus current is roughly constant, which is known as 'Current-Sourced'. However, the term 'Voltage-Sourced Converter' needs to be considered very carefully. The behaviour of VSCs is defined by the software which produces the PWM patterns. Most grid-connected converters today are controlled using DQCI algorithms. The DQCI algorithm control bandwidth might be ~250 Hz. Therefore a DQCI - controlled converter might appear to be truly 'Voltage Source' (note the lack of hyphen) with respect to harmonics above 250 Hz.

6.2 Characterising of Converter Based Inertial Response for Generic Performance Evaluation of Gain and Damping Factors

Starting point for comparison – the rotating machine characteristics

The inertial characteristics of the swing equation dynamics that governs the exchange of active power within the provided operational boundaries can be defined through an equivalent inertial constant, H, and an associated damping constant, D. The practical implementation of the inertial characteristics within the grid forming control will clearly vary from one design to another, but as the nature of the sought response is effectively a 2nd order system similar to the synchronous machine swing equation. This section assumes a linear system meaning that there is no power or energy restrictions when the inertia is provided. A generic interpretation of the swing equation can be represented as:

$$\Delta\delta = \frac{\omega_0}{s}\left[\Delta\omega_{grid} - \left(\frac{1}{2Hs}\left(-K_x\Delta\delta - D(\Delta\omega_{grid} - \Delta\omega_{SM}) + \Delta P_{SM}\right)\right)\right]$$

Where

$\Delta\omega_{SM}$ is the synchronous machine speed

$\Delta\omega_{grid}$ is the electrical grid frequency

H is the inertia constant

ΔP_{SM} is the synchronous machine mechanical power

D is the damping constant

s is the Laplace operator

ω_0 is the rated electrical frequency

The term K_x or synchronising torque constant for the operating point can be defined as:

$$K_x = \frac{E_{grid0}E_{SM0}}{X_{SM}}\cos(\delta_0)$$

Where E_{SM0} is the synchronous machine back-EMF voltage and E_{grid0} is the voltage at the Connection Point, X_{SM} is the synchronous machine reactance, δ is the rotor angle. Figure 10 shows the block diagram of a simplified synchronous machine.

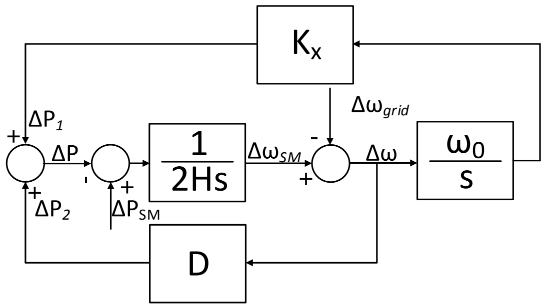

Figure 11. Simplified synchronous machine diagram

The transfer function characterising the synchronous machine electrical power response ($\Delta P = \Delta P_1 + \Delta P_2$) in front of a grid frequency disturbance ($\Delta\omega_{grid}$) is:

$$\frac{\Delta P(s)}{\Delta\omega_{grid}(s)} = \frac{\frac{Ds^2}{\omega_0} + K_x s}{S^2 + \frac{Ds}{2H} + \frac{K_x\omega_0}{2H}}$$

The modelling again assumes that the input mechanical power stays constant, so the power outputs and electrical frequencies are modelled as disturbances from equilibrium during an event. That transfer function defines a damped resonance which all real synchronous machines have. The damped resonant frequency is determined by:

$$\omega_n = \sqrt{\frac{K_s\omega_0}{2H}}$$

and the damping is determined by:

Damping

When incorporating the inertial characteristics of the swing equation in a control system using any design, the VSM/GF control designer has the choice of designing in a particular level of damping that is (probably) not available for a machine designer and when specifying what 'contribution to inertia' means, one would need to consider the level of damping of the response and whether that is controller, or internally simulated damping, or whether the damping power is exchanged with the AC power system.

The damping of the rotor circuit of a simplified synchronous generator is, as also used in figure 10, often represented as a static feedback between Delta speed and the summing junction for power terms. For the purpose of discussing the damping effect from the synchronous machine damper windings and how such damping can be represented with a GFC, it is illustrative to place the damping branch as a derivative term between Delta angle and the summing junction for power terms, which then gives two parallel power branches that define the output power of the machine. The first term is unchanged from figure 10 and represents the power transfer due to the angle difference between the machine back emf and the grid voltage, whereas the second term is proportional to the frequency error or slip and represents the electrical damping power that is exchanged with the AC power system. This is shown in Figure 11 and is equivalent to Figure 10.

In the 2nd control diagram in figure 12, the green parts are purely within the control and the damping power is therefore named 'ΔP2Sim'. However, the two representations will not give the same exchange of active power at the terminals of the units; whereas the upper diagram exchanges ΔP1+ΔP2, the lower diagram only exchanges ΔP1.

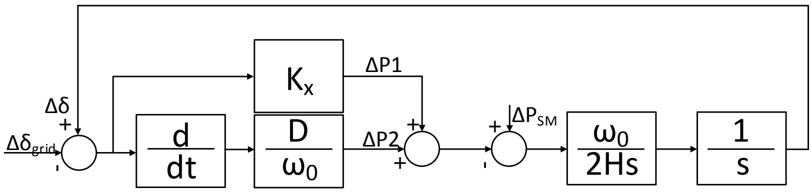

Figure 12. Block diagram representation of simplified synchronous machine model shown in Figure 8.

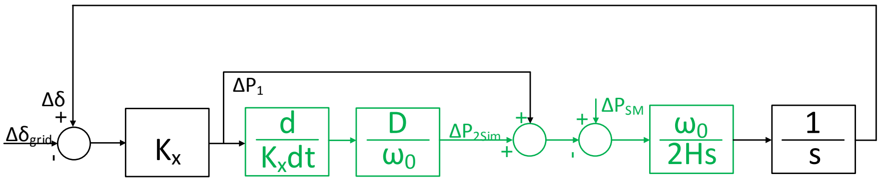

Figure 13. Equivalent representation of the system in Figure 10 where the damping branch is simulated within the converter control rather than exchanging physical power.

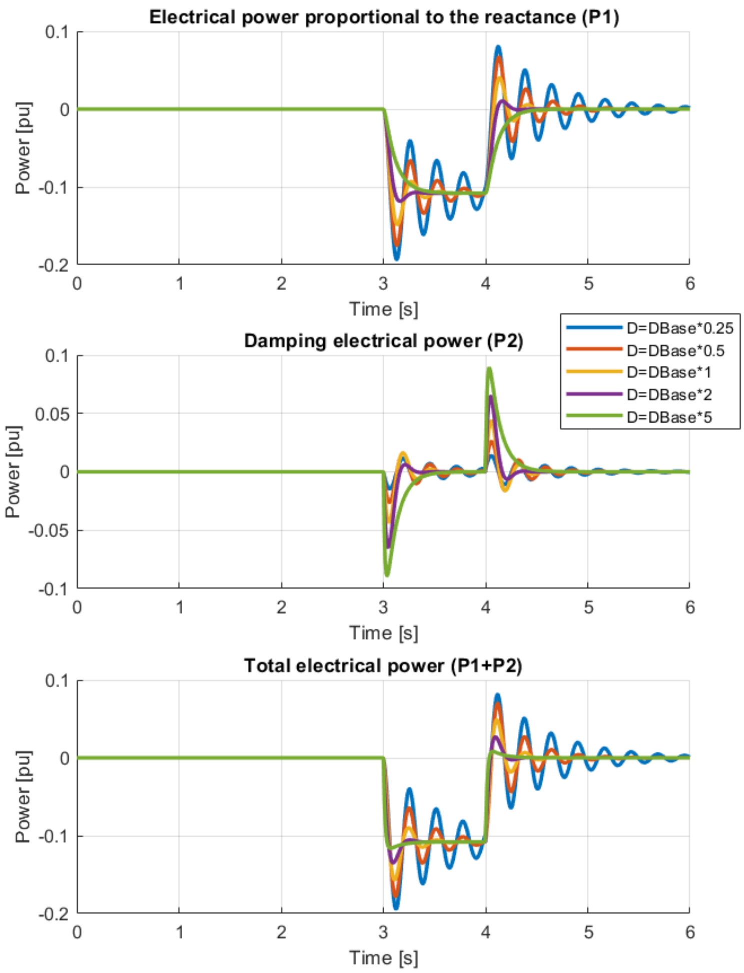

Figure 14. Comparison of real and simulated powers during an under frequency event as a function of the level of damping.

The simulation results in figure 13 show the influence of the amount of damping on the components of active power where the upper plot is ΔP1, the middle plot ΔP2 and the lower plot is ΔP1+ΔP2 in front of a frequency ramp of 1 Hz/s from 50 Hz during 1s. The control system can be designed with a high level of internal damping that would effectively make the rotor model very reluctant to engage in active power oscillations and give a smooth damped response to a grid frequency disturbance. However, as seen in the top plot of figure 14, the level of damping is also clearly affecting the speed by which the converter responds with active power to the frequency event, if the 2nd plot is an internal control signal only and not physical power.

External damping is artificial for a converter running a control that includes simple rotor circuit dynamics and would require a differential feedforward component in order to artificially create the necessary angle across K_x to also deliver ΔP2. Internal damping gives more robust control implementation that follows the notion of controlling the converter voltage as a low bandwidth voltage source, since there is no differential action acting directly on the converter angle.

Testing:

The selection of the gains H and D will have an impact on the system performance. Figure 15 and figure 16 show the frequency response of the system based on the transfer function $\frac{\Delta P(s)}{\Delta\omega_{grid}(s)}$ described at the beginning of the section the varying of the damping and the inertia constants.

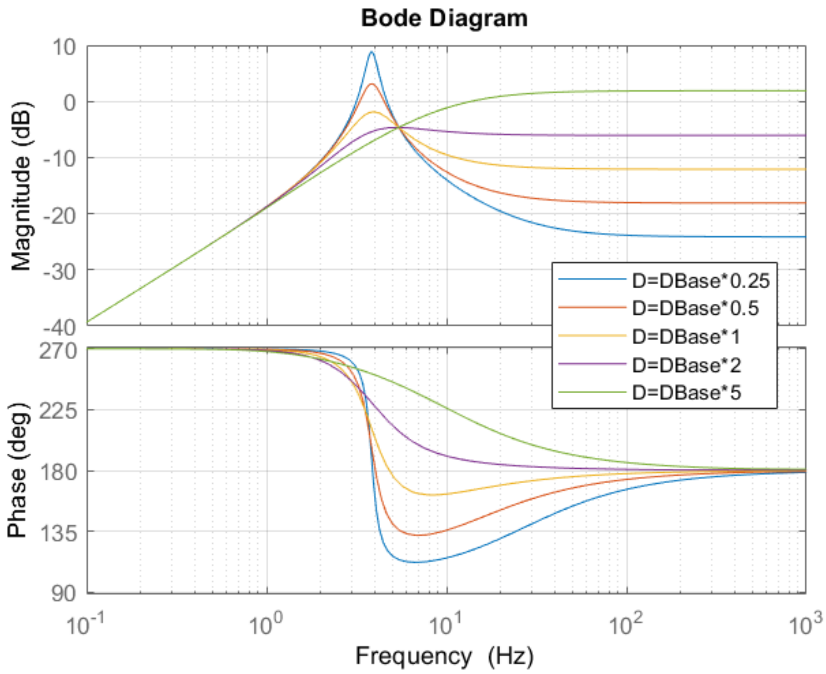

Figure 15. Bode plots for different damping values keeping the inertia constant.

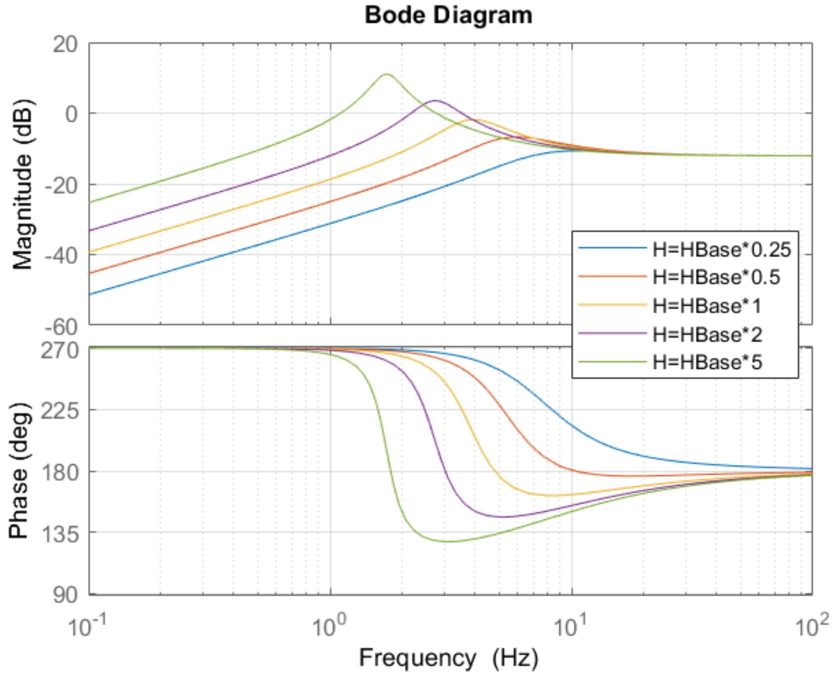

Figure 16. Bode plots for different inertia values keeping the damping constant.